Cogeneration

policies, potential, and technologies

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Proceedings of Cogen INDIA '96

The First International Cogeneration Conference in India

10–12 March 1996

Foreword
Ashok Parthasarathi

Editor
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Foreword

Increasing shortages of electrical energy have become a cause of serious concern. Exponential growth in demand for electrical energy and inadequate capacity addition over the whole of the Eighth Plan period have aggravated the situation. It is not likely to improve significantly in the near future when one considers that the country would be required to add more than 60 000 MW to its present power generation capacity over the Ninth Plan period as against a total addition of only around 18 000 MW over the Eighth Plan period. Such a three-fold increase in capacity addition can only be brought about if all available means of power generation are exploited to their full potential. Promotion of energy conservation and cogeneration should form an important component of such efforts.

Studies have indicated that 6000–10 000 MW of additional power can be generated through use of cogeneration in selected industrial segments. These include sugar, fertilizer, steel, cement, paper, manmade fibre, and chemical/petrochemical industries. The power fed into the grid by industrial cogeneration projects is beneficial both to the country as well as to the individual units. Cogeneration also implies optimum utilization of available fuel resources which could lead to cost reduction and improved competitiveness of our industry.

The Ministry of Non-conventional Energy Sources has for the last three years been promoting optimum bagasse-based cogeneration in the sugar industry for surplus power generation. The National Programme on Bagasse-based Cogeneration being implemented by the Ministry has been instrumental in creating widespread awareness of the benefits of this technology. A capacity of 55 MW surplus power generation has already been synchronized with the grids, while another 75 MW is under implementation. Many more sugar mills are planning optimum cogeneration projects. Efforts of the Ministry have also led to the announcement of power purchase policies by state electricity boards (SEBs)· development of manufacturing capability; and development of expertise for project planning, execution, and operation.

The international conference *Cogen India 96*, organized by the Tata Energy Research Institute (TERI) in New Delhi from 10 to 12 March 1996, not only addressed several key issues related to cogeneration, but also threw up several new ideas. It brought together from all over the world, for the first time, a large number of project promoters, administrators, financiers, and developers with a view to share experiences and expose Indian cogenerators to the latest trends in this emerging technology. Proceedings of this international conference are now being compiled by TERI. The publication is expected to be

of great benefit to engineers in SEBs, independent power producers, industries, energy consultants, utility engineers, equipment manufacturers, etc.

I am sure that this compilation will serve as a useful reference material in the years to come, and I would like to commend the efforts of TERI in this direction.

A Parthasarathi
Secretary
Ministry of Non-conventional Energy Sources
Government of India

Preface

The possibility of cogeneration as a means for utilizing energy efficiently has been receiving considerable attention in India in recent years The current problems of power in the country lend further validity and viability to cogeneration as one option that could help to quickly fill the gap between power demand and supply.

In view of the growing potential and importance of cogeneration in the country, TERI organized the first International Cogeneration Conference in New Delhi on 10–12 March 1996. This volume represents the proceedings of the Conference with a wide selection of papers that were presented at the Conference The Government of India and several state governments have been providing a number of incentives and concessions to promote cogeneration in India, and details of these have also been provided in this volume, so that industry is better informed about the policy framework within which investments in cogeneration are to be made

The conference was well attended, with more than 225 participants. Although the majority of the participants were from India, several were from the European Union, North America and from South-east Asia as well The conference attracted several professionals, policymakers, academicians, and government officials from there regions. Many Indian and multinational companies involved in cogeneration also participated in this conference.

The book is divided into sections based on the structure of the conference which covered wide-ranging issues including the technical potential for cogeneration, regulatory and financial aspects, and cogeneration technologies based both on the use of fossil fuels and renewable energy sources. Several case studies presented by Indian industries and their foreign counterparts indicate that there exists substantial experience in cogeneration which needs to be shared and that there are several unexplored avenues for tapping unexploited potential The section which deals with the innovative financial and regulatory aspects has presentations related to joint implementation, a concept which provides added scope in the financing of advanced technology based cogeneration systems.

The two technology sections – large cogeneration systems and the small and renewable energy-based cogeneration systems – are well-covered in the papers presented, but most of them are based on steam turbines. However, a few presentations on small gas turbines in the range of 1–3 MW, capable of using both conventional and non-conventional fuels, were also made, and these have been included.

Several interesting case studies dealt with the Indian experience in both the renewable as well as conventional fuel-based cogeneration systems, have been included. These case studies are from several sectors: cement, chemicals, petrochemicals, paper, iron and steel, sugar mills, and other renewable energy-based cogeneration systems. Some of the case studies were on international negotiations for setting up of cogeneration plants, grid interfacing and contractual issues.

In the section on international experiences, there were a wide variety of topics presented, ranging from cogenerated power tariffs, cogeneration policies in the Organization for Economic Cooperation and Development countries, waste heat recovery from cement plants, biomass-based cogeneration in Denmark, which also dealt with grid-interfacing issues, and biomass-based small cogeneration system experiences in the Association for South East Asian Nations region.

This volume has taken a long time in the making with several excellent presentations and visual materials being developed into publishable papers. But we hope that the final product would prove to be worthy of the effort put in and provide literature which would be useful in a field which is growing in importance.

R K Pachauri
Director, TERI

Acknowledgements

The book is based on the proceedings of the first international cogeneration conference in India - COGEN India '96, which was held in New Delhi in 10-12 March 1996 We gratefully acknowledge the contribution of the authors, Ms Meena Srikumar for editing and manuscript preparation, Ms Anshu Sharma for assistance in design and layout, R K Joshi for graphic assistance, and Ms Geeta Sood and Ms K Y Valsa for carrying out the editorial corrections These acknowlegdements would be incomplete without the mention of Dr R K Pachauri and Dr Leena Srivastava for their encouragement and support.

Session I

Inaugural Session

Welcome Address

R K Pachauri[1]

Mr N K P Salve Honourable Minister for Power; Prof. P C Kurien, Honourable Minister for Non-conventional Energy Sources; Mr Ramani, colleagues, ladies and gentlemen. It is my privilege to welcome you to this conference, which is the first of its kind dealing with cogeneration in India This initiative is timely in the wake of the liberalization efforts initiated by the Government of India which have been in existence for a few years now It is through initiatives such as cogeneration, and the possibilities and options for supply of energy through investments in cogeneration that the energy sector is likely to develop and grow in the future.

The liberalization measures that have been undertaken by the Government of India will not merely provide an opportunity for new investments coming into power generation and the energy sector in general, also, they will pave the way for the emergence that new policy options through the change in the structure and the pattern of investment that is taking place There would also be new opportunities for policies to be formulated that would bring about these investments in an optimal and accelerated manner This is one aspect of the current phase of liberalization in the opening up of the Indian economy that perhaps does not get adequate attention. The policy implications are very vast and very deep, as, through options like cogeneration or the development of wind farms in this country, we are creating the building blocks of developing the energy sector in consonance with market forces and the economic rationale.

I remember, in 1976, when I was at the Administrative Staff College of India, I had organized a national seminar on energy. Mr K C Pant was then Minister of Energy, and, in his address he very candidly said· 'I don't know if India has an energy policy'. It is interesting that with the developments that are taking place, we now find the linking up the different sub-sectors of the energy sector which obviously will result in the formation of a coherent energy policy. The very fact that we have got three ministries sponsoring this particular conference is a clear indicator that these linkages, this networking between different departments, between different subsets of policies is really going to shape overall energy developments and energy policies in the future. And, if I may carry this

[1] Tata Energy Research Institute Darbari Seth Block, Habitat Place, Lodhi Road, New Delhi - 110 003, India

[illegible] further it is also possible that even our external relations are likely to [illegible] by the implications of the wave of liberalization that is taking place in the [illegible]

[illegible] want to give two examples that are of relevance to energy sector development. There is [illegible] possibility of much greater trade in electricity between the countries of South Asia [illegible] and the initiatives that has been taken by the Ministry of Power and the Government of India are all leading in that direction. There is also a very strong likelihood that there will be a much greater volume of international trade in natural gas, and [illegible] have been involved in promoting the possibility of natural gas imports from other gas [illegible] regions in neighbouring countries, we now see that this is becoming [illegible] of energy policy within the Government of India and also within the governments of countries of this region.

[illegible] I would like to just briefly touch on TERI's role. TERI is a non-profit independent research institution. We have a total staff in excess of 400. We have had [illegible] growth has been into every element of the energy sector and [illegible] the environmental aspects of energy production and use. In that context, it is most heartening to see that options such as cogeneration, which involve issues of biomass energy and its efficient utilization, and feeding the surplus energy into the grid of the power system in this country, provide us with an opportunity whereby we can play some kind of a modest catalytic role in making this happen. Through the improved use of biomass for cogeneration purposes and cogeneration of all kinds, we are really going to attain much higher levels of resource use efficiency. That is the central objective which guides the activities and objectives of our Institute. Here I would like to mention a large number of projects that we have investigated. My colleague, Mr Pradeep Dadhich, has been working towards how one can promote investments in cogeneration using bagasse in the sugar mills of this country.

There is a possibility that there would be projects under the so-called option of joint implementation under the climate change convention. This is the option of activities implemented jointly essentially to reduce CO_2 emissions, where one country or a party in one country makes investments in another country to see that efficient use of energy is made and thereby reduce CO_2 emissions. Cogeneration therefore represents one such potential and it is a matter of pride for us that we have been involved in reviewing several possibilities in this area in developing detailed projects reports to make this happen in the future. We are also involved in bringing about partnerships between the private sector and the government.

I would like to end by saying that there is a need for a very major innovation in the way we manage the power sector in this country in respect of allowing for independent regulation. If one looks at our experience and at that of the other countries as well, one realizes that not only do independent regulations bring about much greater ease in transactions in the energy sector but that they also lead to transparency of decision-making and building greater confidence among investors as well as the [illegible] public. This is a possibility by which the entire power industry in this country could be transformed rapidly and it would allow for much greater opportunities whereby cogeneration [illegible] power generation and small-scale power generation can [illegible] apart from the [illegible] projects quite a number of which are coming up in this country. I would [illegible] to you [illegible] and I hope [illegible] conference [illegible] Thank [illegible]

Cogeneration: Overview and Potential

Pradeep K Dadhich[1]

Introduction

generation as a technology has been in existence for over several decades now, but was not given due attention by the industrial sector as cheap power and fuel were abundantly available. However, after the 1970s, the energy crisis has forced industries to adopt energy-efficient technologies and reduce excessive dependency on external energy supply. Governments all over the world have introduced several financial and other incentives to promote energy-efficient technologies. The need for cogeneration is felt increasingly today in India because of increased energy shortages. India, today, experiences a peak power shortage of 27% and an energy shortage of about 9%. The economic liberalization processes in the country are likely to increase the economic growth from the normal past growth rates of 4–5% to 12–15%. The energy requirements to meet the increased growth rate will increase substantially. To meet this growing demand for power, the Government of India has now allowed private sector participation in generation, transmission and distribution.

The new reforms have evoked tremendous interest in the private sector, and it has presented over 90 proposals to the Government of India. These proposals have identified a wide range of projects, in terms of capacities, fuels, as well as renewables. Cogeneration has a significant role to play not only because it is an energy-efficient and an environmentally sound technology but also because of the large untapped potential in the country.

The Need for Cogeneration

Power Deficit

The power sector in the country is unable to meet the current demand and has a peak demand shortage of about 27% and an energy shortage of about 9%. Studies have indicated that the total demand for power will be 120 000 MW by 2000 AD. To meet this capacity demand, an additional capacity of around 12 000 MW must be added every year

[1] Tata Energy Research Institute, Darbari Seth Block, Habitat Place, Lodhi Road, New Delhi 110 003, India

for the next three to four years to the present installed capacity of 84 000 MW. A need for new capacity additions depends largely on local economic growth and the utility's construction schedules.

The industrial sector today consumes approximately 34% of the total electricity generated in the country. It has reduced its reliance on utilities, and there has been a dramatic drop of about six per cent of total power supply to the industry. The industrial sector has projected an annual growth rate of around 12%. High-quality stable power will be required to sustain such a high growth rate, and to keep up with the overall economic growth. The industry, therefore, has relied on captive power generation, which is primarily diesel-based generation, and is estimated to be around 10 500 MW. This type of captive generation is not only expensive but also inefficient when compared to cogeneration.

Energy-efficient Technology

Cogeneration is an energy-efficient technology as it utilizes the low-grade exhaust heat from the steam turbine (which is usually rejected in the condenser) for process heating. This enhances the efficiency of energy utilization from 35% in the conventional power generating system to 70–90% in the cogenerating system. Figure 1 indicates how cogeneration efficiency compares with the conventional process heating and conventional power generation.

Table 1 indicates the percentage savings in fuel consumption, comparing individual heat and electricity production with power produced in cogeneration using different fuels.

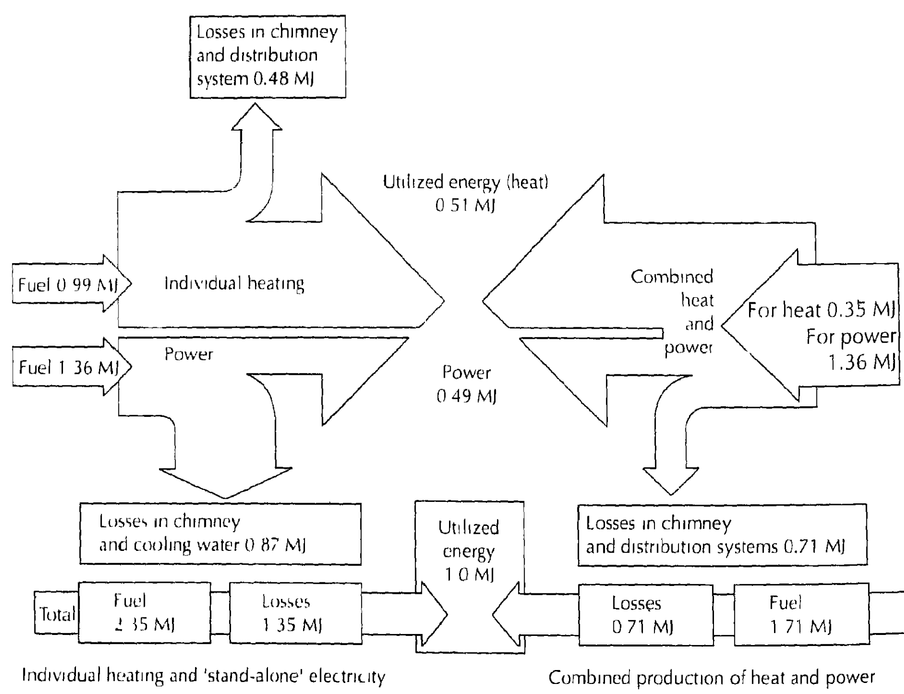


Figure 1. *Cogeneration: an efficient and cheap source of power*

Table 1

Comparison of percentage saving in fuel consumption achieved in individual heat production and heat produced in a cogeneration plant

Coming from percentage savings in fuel		Combined production of heat and electricity		
		Coal	Oil	Gas
Individual heat production	Coal	72	73	80
	Oil	63	65	73
	Gas	50	53	63

A Cheap Source of Power

Today, state electricity boards (SEBs) are seeking cheaper sources to generate power. A cogeneration system can compete with utility central power stations that have enjoyed large economies of scale. Cogeneration becomes additionally attractive against diesel generating (DG) set generation. The cost of power generated by DG sets without cogeneration will range between Rs 3.50–4.00 per kWh depending upon the type of fuel and mode of financing.

The analysis of the cost of power cogenerated in a sugar mill and in other modes of cogeneration systems indicates that the price of power cogenerated varies between Rs 0.49/kWh and Rs 1.35/kWh. Industries that use economic cogeneration systems even without supplying to the utility usually pay off their investment within three years. Hence, the government should encourage cogeneration instead of captive power generation.

Low Gestation Period

Cogeneration plants can normally be commissioned within two years from the conception of the project. Coal thermal power plants normally take about five years before commissioning, whereas gas-based power plants normally take about three years before commissioning. Under the current situation of extreme power shortages, cogeneration potential should be exploited to bridge the gap between demand and supply and preference should be given to cogeneration which is not only a long-term option but also environmentally sound.

Low Pollution Levels

All stages of energy conversion paths normally result in emissions; the most critical pollutants are CO_2, SO_2, NO_x, and particulates. These are significantly reduced due to low fuel consumption levels in cogeneration systems.

Cogeneration Potential

Cogeneration potential primarily exists in the industrial and commercial sectors. The Tata Energy Research Institute (TERI) had carried out studies to determine the cogeneration

Table 2
Cogeneration potential in different industrial sectors

Industry	Potential (MW)
Alumina	59
Breweries	250–400
Caustic soda	394
Cement	78–100
Coke oven batteries	200
Commercial sectors	175–350
Cotton textiles	506
Dairies	70
Distilleries	2900
Fertilizer	850–1000
Iron and steel (integrated plants)	362
Manmade fibre	523
Paper and pulp	850
Petrochemical	250–500
Plywood manufacturing industry	50
Refineries	232
Rice mills	1000
Solvent extraction	220–350
Sponge iron	225
Sugar	5200
Sulphuric acid	74–125
Tyre plants	160–200
Total	14628–15586

potential in the country. Table 2 indicates the cogeneration potential in India in the different industrial sectors. Since the studies is based on the information supplied in the questionnaire, the estimates are likely to be very conservative. Maximum cogeneration potential in the country is likely to exceed 20 000 MW. The potential can be much higher than the figures mentioned here if an industrial park concept with cogeneration facilities is taken into consideration.

Technology Status in India

Boilers

The major boiler manufacturers in India include the Bharat Heavy Electrical Ltd (BHEL), Thermax, Walchandnagar Industries, Texmaco, ISGEC, IBPL, Lipi, ACC – Babcock, and others. Most of the major boiler manufacturers have collaborations with leading boiler manufacturers in the world, e.g., Combustion Engineering, Babcock and Wilcox, and John Thompson. Both conventional and fluidized-bed combustion (FBC) boilers are being manufactured in India.

Steam Turbines

There are five manufacturers of steam turbines in India: APE Belliss, Triveni Engineering Works, Kessels, Rolls Royce, and BHEL. APE Belliss, Kessels, and Triveni manufacture turbines in the lower rating range, starting from a few hundred kilowatts to 5–6 MW. BHEL

manufactures steam turbines in a wider range of capacities (1–500 MW) for thermal power plants. These turbines are available in different configurations, i.e., simple back-pressure, condensing, extraction condensing, and multiple extraction turbines.

Gas Turbines

In India, gas turbines are available from BHEL, Triveni Engineering Works, and DLF Energy Systems, and Kirloskar Oil engines. While BHEL and Triveni supply heavy duty industrial gas turbines (typically in the range of 4.5–38 MW), DLF Energy Systems supply aero-derivative gas turbines (1–5 MW range). BHEL is the only manufacturer of gas turbines in the country and these machines are made in collaboration with General Electric. Triveni and DLF Energy Systems supply Ruston and Allison-GM machines, respectively. Typically, gas turbines operate at an efficiency of 22–26% (typical Indian operating conditions) in the lower ratings up to 5 MW. Significant developments have taken place in the last one year and new collaborators, specially in the size range of below 1 MW European turbines have also launched two of these products in India in the size range of 3–5 MW.

Diesel Engines

There are various manufacturers of diesel engines in the country manufacturing both high-speed and medium-speed engines. Low-speed and medium-speed engines are more suitable for cogeneration applications. The major manufacturers in India are Kirloskar Pielstick, Garden Reach, K G Khosla, and Wartsila. The new medium-speed engines proposed to be manufactured in the country will be able to use heavy fuel oils of up to 700 centistoke (at 50 °C) These engines in the range of 4–6 MW would typically operate at an efficiency of 38–43%. In India, there are only a few installations of diesel engine-based cogeneration systems with capacities up to 52 MW.

Waste Heat Boilers

The main manufacturers of waste heat boilers in the country are BHEL, Thermax, Cethar Vessels, ISGEC John Thompson, Texmaco, Larsen and Toubro, and Kaveri Engineering. Waste heat boilers of ratings up to 62 tonnes per hour (tph) with single pressure and 105 tph with dual pressures are being manufactured in the country. Among smaller units, used for operation in a cogeneration system, is a 38 tph waste heat boiler used to produce steam at a pressure of 15 kg/cm^2 and 256 °C temperature. Installed in a refinery, it uses refinery gas as the heat source. However, most of these waste heat boilers have been supplied to fertilizer and chemical industries and refineries using process gas, natural gas, and residual oil as the fuel.

Conclusion

Several plants are now exploring the possibility of cogenerating and also exporting to the grid because of the changes in the current policies in the Electricity Supply Act for private power generation. The primary ones among these are the sugar mills which have now started exporting over 90 MW to the grid.

However, the technological gaps in small-size cogeneration systems for sizes less than 2 MW needs to be filled in by importing the appropriate technology.

Cogeneration: Are We Missing Out on an Opportunity?

R V Ramani[1]

Introduction

The country is, today, going through a power struggle and the future looks even more bleak. In a paper presented by Mr R D Aga, the late Chairman and Managing Director of Thermax at a seminar in Washington in October 1993, certain very thought-provoking points were raised. A quote from his paper is presented here:

> *Dr David Jhirad of the US Agency for International Development talks of the triple bind in which a number of developed countries, including India, are caught: the lack of funds to generate, transmit, and distribute electrical power to serve the needs of a growing economy; the deteriorating performance, financial and technical, of the existing utility companies, which have to generate funds for growth; and the environmental pollution of air and water to which fossil fuel combustion is a major contributor.*

There is a flurry of activity on the power front in the country today. However, in real tangible terms, the results are dismal.

- Over 250 memorandums of understanding (MoUs) have been signed, but very few have reached even the stage of financial closure.
- There are heated debates about the merits of competitive bidding versus non-competitive bidding, again with no tangible direction or results.

Other points being mooted are outlined below.

- Should wheeling and banking be allowed?
- What should be the fuel policy, liquid or otherwise, that we need to have?

[1] Thermax Ltd, Thermax House, 4 Bombay Pune Road, Shivaji Nagar, Pune - 411 005, India.

However, caught in this maze of issues and counter-issues, we seem to be missing out on a vital factor: *decentralized power generation.*

Decentralized versus Centralized Power Generation

For decades, the Indian power scenario has been dominated by large centralized utility plants spread across the country, which are, by and large, operated by state or central electricity boards. This was relevant in the past and will have relevance in the future as well.

However, given the fact that such state electricity boards (SEBs) are strapped for funds, new private utility (centralized) power generation projects are not getting off the ground as MoUs for small independent power producers (IPPs) continue to remain merely on paper. With the rapidly widening supply–demand gap as a result of the growing industrialization, it is quite clear that large capacity addition in the short run is not going to take place and, therefore, may not be a solution in the short and medium term. What then is the solution?

Clearly, the focus needs to be shifted from centralized to decentralized power generation. Decentralized (inside the fence) power generation is very simple. It is cost-effective, has a short gestation period, is fundable, and, most importantly, is hassle free. Decentralized power has been patronized by the industry for some time now, but the approach has been of a reactive nature. It has not been thought through, and, therefore, while it answers the problem of power availability, it is, many a time, not the least-cost option.

It is in this context that 'cogeneration' clearly stands out as a viable solution for decentralized (inside the fence) power generation, not only because it effectively addresses the power problem, but also because it is a real least-cost and fast-track option.

Decentralized Power: The Cogeneration Route

By definition, cogeneration is the simultaneous generation of electrical and thermal energy (normally steam). The idea is simple.

- Conventional utility power plants utilize the high-end potential energy of a combustion process to generate power. A good part of the low-end residual energy is wasted by ejection into the atmosphere.
- On the other hand, a cogen process, in addition to putting the high-end potential energy to use for power generation, utilizes the low-end residual energy for heating some processes, equipment, space, or similar applications.
- Now, given a typical 40:60 ratio of the high-end to low-end energy, it clearly stands out that cogeneration will substantially boost energy utilization by as much as 80 to 100% compared to a conventional power generation process as it puts to use a good part of the low-end energy.

Almost without exception, 60–65% of industries in India need both electrical and thermal energy. Today, these industries either buy their power from the SEBs or generate their own (largely through diesel generators), and meet their thermal energy demands

through captive boilers or other heating equipment. In other words, electrical and thermal energies are independently generated – they are not cogenerated. This fact, in itself, makes almost every industrial plant a potential candidate for cogeneration and, therefore, offers virtually unlimited market potential.

The Indian industry consumes electrical energy at different potential levels through an in-house distribution system. Thermal energy, on the other hand, is required not only at different potential levels (pressure/temperature) but also in different forms (steam, hot water, hot air, hot thermal oil, and so on). This wide spectrum of thermal energy demand offers an excellent opportunity to achieve high levels of cogeneration efficiency by releasing practically very little by way of waste to the atmosphere.

As a tropical country (peak summer temperature: 45 °C+ and country average: 33 °C+), air-conditioning in India is a basic need for the comfort of men (and machines). Until a few years ago, air-conditioning chillers in India were largely driven by electricity. Given the growing power problem in India, users of air-conditioning machines were forced to either switch off such facilities or operate them by installing high-cost captive diesel generators. Fortunately, with the revival of 'absorption cooling systems' (which run on heat instead of electricity) in India, the dependence on power for air-conditioning (or industrial process cooling) is being substantially overcome by a number of industries. This technology shift is motivating many industries to go in for air-conditioning and process cooling even for applications, which were earlier run without such facilities, to improve quality and productivity (like, for example, in cotton yarn spinning). The significance here is that absorption cooling systems prove very effective as a major steam host to achieve a finely balanced and efficient cogen system.

Ironically, in a tropical country like India, for over four decades, air-conditioning was classified by the government as an item of elitist luxury. Therefore, air-conditioning equipment was subject to heavy taxes of up to 200% (import taxes, if imports were permitted at all, were even higher). Mercifully, the onset of liberalization has brought about significant changes, and, today, air-conditioning is classified as less of a luxury. It may be some time before it is seen as a basic necessity, but it may be hoped that this will happen soon.

Now, here is a huge opportunity for cogen. India is a country where 900 million people live for most part of the year under warm weather conditions. Even if we consider a small percentage of this population (basically urban population living in clustered apartments) as a target segment, the potential it offers for air-conditioning is indeed large. Given the problems of power availability and cost, conventional electrical cooling will be expensive and impractical. Added to this is the cholorofluorocarbon (CFC) and ozone layer depletion problem associated with conventional chillers. On the other hand, the idea of providing inexpensive cooling, using the tail-end waste heat of a cogen system through absorption chillers, offers singularly large and untapped potential.

Next to power, another major resource crisis looming over India's industrial infrastructure is the availability of water – whether potable, domestic, or industrial water which is going to be in acute short supply by the turn of this century. Not just the availability, but even the quality of water is going to be a stumbling block. In many places, the water table goes down so substantially in summer that whatever water is available is highly brackish. With growing industrialization, a result of liberalization, the availability of this precious resource is going to be even more critical.

Bad water in India is currently being treated by the conventional 'demineralization (DM) process. The quantity of 'bad' water the DM process can treat depends largely on the total dissolved solids (TDS) in the raw water. Beyond a certain level of TDS, the DM process is rendered ineffective. By way of a solution to the problem, industries in India adopt the reverse osmosis (RO) route which accepts high levels of TDS. However, the RO process also has a problem in that it is a power guzzler. The solution is 'thermal desalination', which uses thermal energy instead of electrical energy to treat water. What is fascinating is that thermal desalination can make use of almost any grade of heat energy from 70 °C hot water to high pressure steam.

From a cogen point of view, thermal desalination becomes a very natural adjunct as a heat host. More importantly, given the flexibility in the grade of heat that can drive a thermal desalination process, it can boost the efficiency of the cogen process through the enhanced recovery of even low-grade heat.

Having looked at the application/system side of cogen, let us take a look at the supply or fuel side options of a cogen system. This opens up a wide variety of options available right across the length and breadth of the country.

- In the non-conventional area, we have a wide spectrum of agricultural residues including rice husk, soya husk, rice straw, wheat straw, bagasse, and a host of other biomass material.
- In the conventional area, we have coal, lignite, as well as light and heavy oils. In the last budget, the Finance Minister has decanalized other light fuel oils like naphtha and kerosene. What is of added significance is that naphtha and kerosene are now available with practically zero import duty.
- In the future (probably by the beginning of 2000), the availability of gas from the Oman–India gas pipeline is expected to provide gas as an optional fuel for industry (existing gas supply in India is fully tied up with current users).

Therefore, we now have a fuel availability position that offers immense flexibility for configuring high efficiency low-cost cogen plants to suit individual industry needs and locations.

Finally, a large portion of the equipment going into a cogen plant (boilers, electrical instrumentation, water treatment, and pollution control equipment, etc.) is inexpensively and easily available in India, and, unlike earlier times, the import of cogen equipment like the prime movers (gas turbines, steam turbines, boilers, etc.) is now freely allowed. Additionally, import of used/reconditioned equipment (which is available in the developed world) has also been liberalized. All this goes to provide a cogenerator with enormous flexibility to configure the most optimal and cost-effective system keeping the energy balance, fuel availability, and equipment specifications in focus.

Essential Future Action

It may come as a pleasant surprise to many of us that even in countries like Europe, Japan, and the US, where the quality and availability of power is no problem at all, cogeneration has been actively pursued and implemented by the industry as a viable mode of decentralized (inside the fence) power generation option. There are industries which have adopted cogen plants for as small a capacity as 500 kW with extremely attractive

operating benefits. If this (the cogeneration option) is true of power-surplus countries elsewhere in the world, it should be even more true for a country like India where the basic availability of power is a nightmare. This section discusses the issues, hurdles, and suggestions that need to be focussed on to make it possible for cogeneration to take off in a big way in India.

IPPs versus Cogen Power Plants

Reference has been made earlier to many MoUs that have been signed for supplying power to the SEBs and projects that have unfortunately not taken off for a variety of reasons. If these MoUs can be looked at as 'inside the fence' cogeneration plants for industries as opposed to IPPs (which sell power to the grid), a win-win situation clearly emerges.

- A private entrepreneur would be happy to pay a price which he would have anyway paid to the grid.
- Likewise, steam would also be priced effectively so that he would pay what was otherwise an expense for his own steam-generating plant.
- Since it is a deal between two private enterprises, which ensures efficiency of performance and effectiveness of payments, a regular commercial deal can be easily configured (no sovereign guarantees/counterguarantees).

What is required is a change of mindset – instead of making a beeline for IPP MoUs with the SEBs, the focus should be on cogenerated power purchase MoUs directly with industries. This is workable, achievable, and realistic.

Liquid Fuel Policy

On the domestic liquid fuel policy, it is imperative that the government (the Ministry of Power) comes out with a clear direction on sanctions and availability of a wide variety of liquid fuels from, and with, a single-window clearance for all sanctions within the Power Ministry. Currently, the issue is being tossed between the Power Ministry and the Petroleum Ministry. This is in spite of the fact that the import of some of the liquid fuels has been decanalized.

SEB Policies

There still exist some electricity boards which are reluctant to permit easy captive generation. If this policy can be reviewed and eased out, it would help the cause of cogeneration considerably.

Propagating the Cause of Cogeneration

There is, perhaps, a need to form an Indian Cogeneration Association, something on the lines of Cogen Europe or ASEAN Cogen. This would act as a single-point nodal agency for sharing, collating, and disseminating the fund of global cogen knowledge and experience so that cogeneration, in the next few years, becomes the buzzword and, in the process, provides some real help to ease the Indian power struggle.

Inaugural Address

N K P Salve[1]

My esteemed colleague Prof. Kurien, Dr Pachauri, Dr Srivastava, Mr Pradeep Dadhich, Mr Ramani, distinguished participants, ladies and gentlemen. I am extremely grateful to Dr Pachauri and TERI for inviting me to address this conference. I feel greatly honoured. To say the least, the subject of the conference is not only of great importantance, but, looking at the needs of the power sector today, it is the most timely subjects as well to discuss.

Indian economy, after five years of economic reforms, has taken off with spectacular success. The industrial growth of the country in 1994/95 was 8.6%, and in 1995/96, from April to September, it is over 12%. Exports are increasing by leaps and bounds. Due to this very spectacular increase, we are able to meet over 60% of the payment for, our imports, whereas, earlier, we would hardly pay 15 to 20% for our imports; and borrow the rest. Once we are able to cover the gap of imports and there is surplus, India economy will never look back; the country would truly be awake; and this would bring about the awakening of a sleeping giant. Another very important aspect of the India economy today is that our inflation has come down, to an all-time low. It is an extremely important factor; in a country where a very large percentage of the people live below the poverty line, inflation is ominous, which we need to curb, and which we have curbed in a determined fashion. And, now, when we look forward to higher and higher growth in this vast country in the days to come, and we realize its potential, we see the need to build a very large and vast infrastructure to be able to get to satisfy the needs of this sleeping giant, which is going to awaken in the days to come.

This affords unlimited opportunities to Indians as well as foreign investors. We need to streamline many things. I have no doubt whatsoever that we have already started doing that. We have learnt a great deal. However, we still have to learn a great deal. But I have no doubt, that perhaps no other country in the world, will be extending this kind of opportunities for technologies and investments, as India would be, in the years to come.

Adequate power generation at economic prices lies at the root of the entire strategy of economic development. Before I spoken the theme of the conference, I take this oppor-

[1] Former Minister for Power, Shram Shakti Bhawan, Government of India, New Delhi.

tunity to present to you what I may describe as a bird's eye view of the present powe situation. Starting with 1362 MW in 1947 when we gained independence, by 1995 Marc we have augmented our generation capacity to 81 000 MW. By all standards, the growt and increase in the generation capacity in the country is certainly splendid. But, the pe capita kW consumption has remained at an extremely low level. Today, it is less tha 300 kWh per annum.

The Central Electricity Authority (CEA) has estimated that the country will need an in cremental generation capacity of 141 000 MW. That will cost, reckoning the cost a today's level, not less than US $150 billion or Rs 500 000 crores. This kind of money i: very difficult for us to find. In fact, because of the resource crunch in the Eighth Five Year Plan, we have not been able to augment our incremental generation capacity as was needed. The Planning Commission reduced the incremental generation we needed be tween 1992 to 1997 from 48 000 to 30 538 MW because of the resource crunch. We will, therefore, be able to generate not more than 20 000 MW. As a result, from the third quar ter of 1995, the country is witnessing a shortage of power the like of which perhaps we have never seen earlier. Cumulatively, the lack of efficiency and irrational tariffs have rebounded so badly that our state electricity boards (SEBs) are in dire physical and financial straits.

One of the biggest impediments in going ahead with the development of the private power sector the way I would like to is that the SEBs are the only buyers of power from the independent power producers (IPPs). When the IPPs come to India, they find that the physical and financial position of the only power purchaser does not inspire confidence, with the result that the counterguarantees to be provided by the Government of India to the first eight fast-track projects, and most of the other guarantees, have yet to see light. Many unforeseen difficulties have come in the way of execution of these guarantees, and, ultimately, I have realized that these kind of guarantees are no solution to the problem. The only solution to the problem is that the working of SEBs themselves must improve.

However, one cannot afford to wait for another 5 or 10 years before the SEBs show any improvements and the laws of economics are very ruthless in that when politicians try to have the better of the laws of economics, they ruthlessly crush everyone else. That is what has happened in the case of our SEBs. If we thought that by giving cheap power to a particular sector (e.g., the vast agricultural sector), or by giving subsidized power *ad infinitum* and *ad nauseum* to certain sectors with the hope that they will return us to power, neither have they returned us to power nor have we been able to keep even the SEBs going the way we would want them to go. In the malfunctioning and extremely difficult power position that I find the country in today, fortunately, the response from the private enterprises, is amazing. This is a tribute to the confidence the industry reposes in the people of this country.

We have also received, until November 1995, 245 expressions of interest to set up power plants with the total capacity of 93 661 MW. This envisages an investment of Rs 339 700 crores. Quite a few proposals out of these are from foreign investors and a time has come for us to evaluate the reasons for the delays caused in the implementation of the policy.

As it is, the gestation period of every thermal or hydel power project is very long and the country cannot afford any further delay The country, as a whole, has so much potential We have all the coal that we need; we have so much hydro potential (our hydro

potential is about 85 000 MW), and our storage potential is about 95 000 MW, of which we have harnessed no more than 18 000 MW so far. In this scenario, both the utilities and the government alike are now looking at alternatives and more flexible options for meeting some of the forecast power demand by means other than the construction of conventional central power stations. Examples of these are wind turbine generators, and small hydro photovoltaic, and, of course, cogeneration systems. The high potential of cogeneration of power to meet the on-site electricity and stream requirements assumes a lot of importance.

In a number of industries, cogeneration even now has scope for export of surplus power to the grid or to other neighbouring industries. One such sector which offers considerable scope to cogenerate power and heat is the sugar sector. Indian sugar mills can emulate the sugar factories in Hawaii and Mauritius, which are generating electricity far in excess of their planned requirement. Many studies made in different industries in India have pointed out that a large potential exists in the Indian industrial sector. What is now required, therefore, is for the industry to come forward to tap this potential, which would not only help in increasing the profitability of the factories, but also go a long way in reducing the demand–supply gap of power in the industry. We, on our part, have notified that projects up to 100 MW, which do not cost beyond Rs 400 crores, need not come to CEA for any clearance. That was the major step, in consonance with the basic theme of economic reforms, to minimize the interference of the government. And, we are also, in a limited manner, promoting and encouraging cogeneration in sugar factories through an Energy Management Centre, which is giving assistance to the states for such cogeneration.

By no means are these measures adequate, nor are they ones which will ensure a miracle of development in the power sector, but we are learning everyday. We want to improve and we are taking more and more steps to ensure that the IPPs and the investors, whether they are from abroad or from India, are able to take their own decisions on merit, and then able to put up efficiently managed plants which would generate power efficiently and at economic prices.

We are aware of the principal advantage of cogeneration – the simultaneous production of power and thermal energy from a single fuel source. Cogeneration must be taken up in right earnest, especially in industries where there is a combined heat and power load, such as in the sugar, pulp and paper, textile, fertilizer, petroleum, and food processing industries. This cogeneration of heat and power by the industry can offer several benefits to individual enterprises.

First and foremost are the fuel savings associated with the recovering of waste heat. Cogeneration may permit the use of by-products which might otherwise have to be discarded, like the coke oven gases in steel making, waste gases in cement plants, and wood wasted in processing for pulp and paper products. Other potential benefits include greater reliability of power supply, cushioning against electricity rate increases, and the opportunity to earn extra revenue through the sale of surplus power to the grid.

Industrial cogeneration also has a number of benefits from the national perspective. A more efficient use of conventional fuels contributes to the goal of conserving energy resources. Cogeneration systems are generally characterized by lower capital investment costs compared with those of central generating stations, mainly due to their smaller size and shorter lead time. They can reduce, to a large extent, the siting and environmental problems as well as the high carrying charges involved in building large utilities

owned by power plants. There are other potential benefits like greater flexibility in meeting demand growth, environmental advantages of fuel conservation, reduced transmission requirements, and the promotion of economic growth. Industrial cogeneration thus becomes an important option for the future electricity supply. There are projections of the doubling of total US cogeneration capacity from 28 000 MW to 63 000 MW by the year 2010. In many European countries like the Netherlands, cogeneration is expected to contribute up to 30% of the total electricity capacity by the turn of the century. I wish we could do that here in our country.

Lastly, another important area which must be mentioned here is the urgent need for greater commitment to R & D effort, and, in this matter, we have the highest expectations from TERI, and higher expectations from Dr Pachauri, specifically with regard to cogeneration. Indian industry has a lot to learn from international experience both in terms of technology and policy and regulatory issues. The case studies of different countries presented in the conference could be very useful for the industry and the policymakers in India, and this conference could help build a sound base for the launch of a massive cogeneration programme in India. Thank you very much.

Presidential Address

Prof. P J Kurien[1]

Hon'ble Mr Salve, Mr Prabhakara, Mr Abraham, Dr Pachauri, distinguished delegates from India and abroad, and friends. It is a matter of great pleasure for me to be associated with this first international conference – Cogen INDIA '96 – being organized by TERI, on the important subject of cogeneration. Various studies have been carried out to estimate the potential for additional power generation through cogeneration in our industries, and it is learnt that 5000–7000 MW power generation capacity can be made available to the country through the adoption of optimum cogeneration. This indicates the inherent potential and importance of the concept.

The present conference is being organized at a very important time, as the policies announced by the Ministry of Non-conventional Energy Sources (MNES) to promote bagasse-based cogeneration are now beginning to take shape. As you are all aware, MNES had constituted a Task Force in August 1993 to assess the bagasse-based cogeneration potential in the country, the status of the technology, and the constraints for the exploitation of the potential. The recommendations of this Task Force were discussed in a one-day workshop held in October 1993, where a large number of sugar technologists and representatives from the turbine and boiler manufacturers were present. Incidentally, the workshop was also organized by TERI. The recommendations of this Task Force formed the basis of the National Programme on Bagasse-based Cogeneration, announced by MNES in January 1994; the Task Force had estimated the potential of surplus power generation in India as 3500 MW.

There is no doubt that the country has made commendable progress in the power sector since independence. The installed capacity, which was hardly 1300 MW in 1947, has now increased to almost around 80 000 MW. Per capita availability of electrical energy has increased from barely 15 units to over 350 units now. The growth in demand has been sustained at more than eight per cent per annum over the last decade and a half, and is projected to grow in the coming decade at rates which are even higher. To meet these growth rates, the Central Electricity Authority (CEA) predicts that we will need to

[1] Former Minister for Non-conventional Energy Sources, Government of India, New Delhi.

add more than 140 000 MW of new power generation capacity by 2007 AD, which will mean a three-fold increase in capacity over a 15-year period.

The current forecasts, however, indicate that we are likely to fall way behind the required capacity additions. As a result, electrical energy shortages, which are around 10% at the overall country level, are likely to increase to over 20%. Peak power shortages will be even higher. The situation could be much worse in some states where own generation is not enough to meet the growth in demand. Typical examples of this would be Karnataka and Andhra, where even the current electrical energy shortages are reported to be of the order of 50–70%.

Primary constraints in the creation of required capacity are the lack of financial resources with central/state governments and lack of supporting infrastructure. Out of the required capacity addition of 140 000 MW over next 10 years, CEA predicts that public utilities will need to add at least 80 000 MW. This will require an investment of over Rs 350 000 crores for generation, transmission, and distribution of power. Equally large investments will be required for matching enhancements in coal mining capacity, railway networks, and other infrastructural requirements. Clearly, these levels of public investments appear to be unachieveable as is also borne out from the actual investments achieved during the last four years of the Eighth Plan. The capacity addition, which was targeted at 38 000 MW, is now expected to be less than 20 000 MW.

Doubts are also being raised regarding the capacity of our environment to absorb the harmful by-products which will necessarily emanate as a consequence of such large amounts of power generation using coal. We are already running out of safe and economic sites for installation of conventional thermal power plants, and, hence, there are all the reasons to even doubt that we will be able to identify locations for the installation of required capacity additions.

The role of various renewable energy technologies has to be viewed in the context of this perspective of the Indian power scenario. Power generation from renewable energy sources such as solar, wind, small hydro, and biomass could help in contributing significant quantities of capacity without further straining the infrastructural resources. Most renewable energy based power technologies, due to their decentralized nature, do not require large investments in the development of infrastructure. Implementation of these projects in the private sector in the 'independent power producer' mode, may also reduce the strain on public exchequer. And, above all, these technologies are environmentally clean. My ministry has been taking a lead in the promotion of renewable energy technologies in the country. A capacity of over 800 MW has already been created based on wind energy, small hydro, and biomass. We plan to reach 2000 MW in the near future, and, subsequent to that, to work towards a 15% contribution from renewable energy resources – in the total electricity generation capacity.

The potential for these non-conventional energy devices is quite large – 20 000 MW power could be generated from wind energy; 10 000 MW from small hydro; 3500 MW from bagasse cogeneration, and over 10 000 MW from biomass, etc. The potential of solar energy is obviously enormous. Our country receives so much of solar energy that only a small fraction of it, if tapped, would be sufficient to meet our entire electrical energy requirements. Over the last four years, power generation from renewable energy resources, has received enormous thrust. During this period, a shift to market orientation and commercialization, mobilization of private investments, and encouragements to

market-driven projects has been tried, with considerable success. Over 2000 MW capacity is now at various stages of planning by private sector investors/promoters.

Cogeneration is a terminology which was made popular by President Carter of the US in 1977. In his famous energy programme, President Carter called upon large industries to cogenerate – combined generation of power and process heat – as this resulted in higher overall efficiencies. This, however, does not mean that the concept was not known or not practiced earlier. Combined generation of heat and power was practiced much before 1977 under the terms 'in-plant generation', 'total energy system', 'by-product power generation', etc. However, President Carter's support and incentives brought cogeneration to its present popularity. and it is reported that more than 25 000 MW of such capacity is installed in the US alone. In our country also, around 2500 MW of such capacity exists, mainly in the sugar, paper, textile, and petrochemical sectors.

The recent thrust on cogeneration in our country, the lead for which has been provided by my ministry under the visionary framework laid by our Prime Minister, is not so much for the promotion of simple cogeneration but is rather for optimum cogeneration. Every industry that requires process heat carries the potential to 'cogenerate' some power also.

Many industries do generate such power and use it for their own needs. They could generate more, but there would be no way to use it, as the state electricity boards (SEBs) would not evacuate it. The country thus lost significant potential for power. MNES, therefore, is acting on two fronts: to convince the industry to generate the maximum power possible for their process heat demand; and, second, to persuade the SEBs to provide evacuation facilities for additional power. We have initially taken sugar industry as it offers one of the largest potentials – as much as 3500 MW – for additional power generation.

We are, therefore, particularly concentrating on states where most of sugar industries are located. I am happy to inform this gathering that, today, six of the nine major sugar-producing states have announced general policies for purchase/wheeling/banking of surplus power produced by cogenerators. These facilities will be instrumental in motivating entrepreneurs to look at full cogeneration potential, by enabling them to work out definitive rates of return on their investments. Assured rates of returns also improve the bankability of projects by reducing their revenue-related risks.

I would also like to say a few words on the strategy supported by us for encouraging cogeneration. As many of you would be aware, we have been advocating a flat rate of power purchase of Rs 2.25 per unit, escalated at an uniform rate of five per cent per year. This was initially considered in contrast to the two-part tariff formula announced by the Ministry of Power. We, however, feel it was necessary to announce a flat rate for all congenerators, primarily because it would be very complex to segregate costs of projects for in-house use and for producing sold power. The interpolation required in view of varying plant load factors would also have been complex. Further, distribution of variable costs into those for power and those for sugar mills, would also be difficult. Lastly, since bagasse is a captive fuel, and extra power is being generated mostly by its efficiency improvement, it would be impossible to place a price on it as required under the two-part formula. I am happy to note that the states are generally in agreement with our contentions. I would suggest that a similar approach should be adopted for all cogeneration projects, whether they are coal, oil, or waste heat, or any other fuel based processes.

Coming back to the sugar industry, it is the sector that has been taken up initially by us for promotion. I am sure that this gathering of experts is aware of the keen interest expressed by sugar industries in revamping their cogeneration projects for production of surplus power. I have been told that at least 20 large sugar mills, in the cooperative and the private sectors, have already prepared concrete project reports for a capacity which will add up to more than 200 MW. This is apart from the around 100 MW likely to be available to grids by the end of the year. We must all discuss what can be done to ensure that these projects are implemented, and are operated to their true capacity. Unfortunately, the last two years have not been very profitable for the sugar industry, and, hence, the cooperative sector, in particular, has little surpluses to invest. Representations were made to us for relaxation of conditions under our demonstration scheme so that cooperative mills could also compete for incentives. We did that during the last year after due consideration. Though has improved the attractiveness of projects, yet, it has not been enough to facilitate any project in a cooperative mill. I feel that the state governments should come forward to offer additional incentives in the forum of counterguarantees, additional subsidies, contributions towards equity, etc. After all, cooperative and public sector mills account for 75% of the mills, and, if they are unable to implement cogeneration projects, all our efforts would be infructuous.

I do not think it is necessary for me to emphasize advantages of bagasse cogeneration to this gathering of experts. It is now well known that the bagasse-based congeneration projects are not only economical by themselves in long run, but are also likely to improve the economic viability of the sugar-making process. Moreover, the projects will be of immense benefit to the country as they will not cause additional pollution; will not be a strain on public exchequer; and will offer a decentralized means of power generation, reducing transmission losses. I also believe that bagasse is a valuable national resource, which should be utilized to its maximum potential by each sugar industry, without wasting it in any manner.

After our success with promoting cogeneration in the sugar industry, the Ministry now intends to enlarge its promotional programmes to other sectors. Recently, initial discussions were held with the paper industry with this objective. As you all would be aware, the energy requirements of the paper industry are also quite conducive for cogeneration. It has been estimated that an additional 200 MW of power could be generated if all the potential was to be utilized. Apart from this quantum of power, exploitation of its fuel cogeneration potential will also make our paper industry more competitive in the global sense. As of today our large mills cogenerate only 40 to 60% of their power needs, compared to around 80% worldwide. The petrochemical, steel, fertilizer, and cotton textile industries also offer significant potential, which would be taken up gradually.

Finally, I once again express my pleasure at having been invited for this important conference. I do hope the deliberations in the conference will help furthering the awareness, understanding, and information exchange among the various involved groups. The exhibition accompanying the conference is also likely to fulfill a felt need, and will definitely help in information dissemination regarding products, processes, and equipment available in the country as well as abroad. I, therefore, wish it a grand success. Jai Hind.

Session II

Regulatory and Policy Issues

Government of India Policies on Cogeneration[1]

Ministry of Power[2]

P Abraham
Secretary
D.O. No. 6/1/Tariff/Captive Power/95 9 October 1995

Sub: Private Power Promotion through Captive Power/Cogeneration route.

1. Since the announcement of private power policy of the Government of India in 1991, a number of proposals, including a large number of proposals from foreign promoters, have been received through Independent Power Producer (IPP) route. However, as the gestation period for large power projects is long, we will be able to complete very few projects in the near future and, therefore, we would face huge shortage of power. At the end of 1996-97, the energy shortage is visualized at 15% and peaking shortage at 30%.
2. There is a need, therefore, to open an alternative route other than Private Generating Company, where the industries themselves will be interested to meet their own power demand by pooling resources together. Captive Power Plants offer such an alternative. The captive power plants of industries may be allowed to sell their surplus power, if any, to the Grid, on a remunerative tariff, as per mutually agreed terms. Setting up of captive power plants would quickly add to the generating capacity in the country. I would also like to add that Cogeneration and small power production is an important ingredient of private power policy in a number of countries.
3. Few developing countries, in their recent restructuring process of the electricity sector have brought out important changes, among others, open access to the transmission system of the State grid on payment of mutually agreed wheeling charges for facilitating new entrants in the power sector on the captive power/cogeneration route. The States can assure such an entry to the new proposed captive/cogeneration power plants.

[1] Reproduced from the circulars issued by the Ministry of Power, Government of India

[2] Government of India, Ministry of Power, Shram Shakti Bhawan, Rafi Marg, New Delhi - 110 001, India.

4. You may, therefore, create an institutional mechanism which may allow captive power units an easy and automatic entry into the Power Sector by quickly clearing captive power applications by State Governments, and giving them rational tariff for purchase of surplus power by the grid and third party access for direct sale of power to the other industrial units.

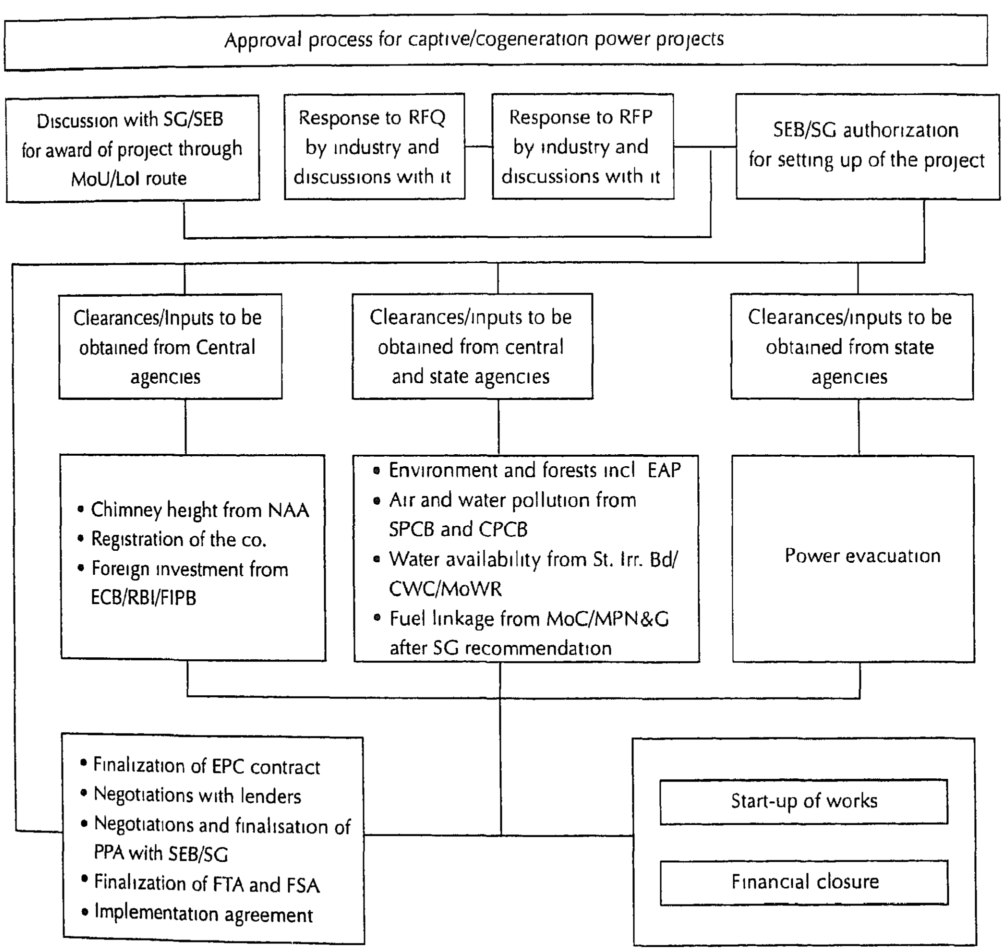
To
All Chief Secretaries

Yours sincerely
Sd/-
(P Abraham)

1 At the time the Private power policy was launched in 1991, the methodologies regarding independent power projects (IPP) and not totally crystallized. Therefore, like all other countries – developed and developing – the initial project solicitation was through the MoU route.
2. From the experience gained over the past three years, it is now possible to follow the bidding route for IPPs in the interest of transparency as well as to encourage competition, which would no doubt also help in getting a better deal for the State Electricity Boards (SEBs). We can resort to bidding route only when the State governments have undertaken an integrated resource planning exercise thereby enabling them to identify the system needs, additional capacities required, the technical and environmental characteristics and the mode of despatch etc. The next stage would be preparation of feasibility reports and obtaining difference clearances and linkages for the projects. Bidding route also requires that financing arrangements, PPA, legally enforceable FSA etc. are standardized and published.
3. The Minister for Power had written to all the Chief Ministers way back in October, 1993 that it is necessary to introduce competition by asking for price bids. I had also written to you in November, 1993 to fix a date beyond which SEBs would not offer any projects except through the bidding route.
4. We had also organized a number of workshops for State/SEB officers so that they could prepare scientific documents. Notable among these workshops was the technical workshop on competitive bidding on private power organized with the help of the World Bank in Hyderabad in June '94 which was attended by a large number of State/SEB officials. In fact, some of the States like Andhra Pradesh, Maharashtra, Rajasthan and Haryana have finalized their latest batch of projects on a partial bidding route We are again going to hold a training on "Bid Solicitation, Project Appraisal and Negotiation" in ASCI Hyderabad in January-February 1995 for the benefit of State/SEB officials. We hope that you would be nominating suitable candidates to take advantage of this training course as well.
5. In its effort to play the role of Development Financial Institution, PFC has established the Technical Assistance Project for Private Power Development - US $ 20 million development soft loan with an interest rate of 12.5% and repayment period of 20 years including therein a moratorium of up to 5 years - with World Bank assistance. Services of experienced consultants for project preparation, preparation of pre-feasibility and feasibility reports, detailed project reports, bid preparation/evaluation, selection of Independent Power Producers, negotiation of Power Purchase and other related Agreement with the selected Independent Power Producers can be financed under this loan. The utilization of such services could even save precious time in identification of various risks, analysis of the project proposals from finan-

cial and technical angles, ensure proper allocation of risks between the developer and the SEB, resulting in reasonable tariff for purchase of power and expeditious implementations of these projects.

6. The Ministry has now prepared a set of guidelines to assist the State Government in following the bidding route, a copy of which is enclosed. We hope that these guidelines would be useful to you while adopting the competitive bidding route. We have also decided that all future projects should come through the process of competitive bidding. In fact, the Central Electricity Authority is being asked not to entertain any future proposals which have not been processed through the procedure of competitive bidding. It is, however, recognized that the SEBs have already entered into numerous MoUs the validities of which have not yet expired, and the SEBs might be at various stages of negotiation with the parties. Therefore, some time would need to be allowed to see the outcome of these MoUs. However, this period should not be an indefinite period and it would be advisable to weed out the non-serious proposals and include those schemes on the competitive bidding process as well. We would like to receive suggestions from you regarding the period these MoUs should be permitted for achieving financial closure.



Government of India Policies on Cogeneration[1]

Ministry of Non-conventional Energy Sources[2]

Circular

Sub: National Programme on Bagasse-based cogeneration: modifications in schemes

This is further to this Ministry's circular Nos.1/6/93-CPG & 1/7/93-CPG dated 5th January 1994 and No.1/6/93-CPG dated 1.8.1995 regarding National Programme on Bagasse based cogeneration. I am now directed to convey the administrative approval of the government of India to the implementation of the national programme incorporating the following schemes:

1. Modified scheme for demonstration cogeneration projects in sugar mills
2. Modified scheme for interest subsidy to financial institutions that provide term loads for cogeneration projects.
3. Scheme for financial assistance for preparation of detailed project reports.

The modified schemes will be applicable with effect from 2.9.1996 and will supercede all other previous circulars in this regard.

1. Modified scheme for demonstration cogeneration projects in sugar mills:

   • A maximum of 12 demonstration cogeneration projects will be taken up in sugar mils in those of the major sugar producing states which have announced a gen-

[1] Reproduced from the circulars issued by the Ministry of Non-conventional Energy Sources (MNES), Government of India (Dated: 31/10/1996). © Government of India.
[2] Government of India, Ministry of Non-conventional Energy Sources (Power Group), Block No.14, CGO Complex, Lodhi Road, New Delhi - 110 003, India.

eral policy for purchase wheeling/banking or third party sale of surplus electricity from all bagasse based cogeneration projects. Out of a maximum of twelve (12) projects, at least nine (9) will be in cooperative/public sector sugar mills and the balance could be taken up in private sector sugar mills.

- For projects selected by MNES from private sugar mills, MNES will provide a one-time capital subsidy of up to 30% of total equipment cost, or up to Rs 70 lakhs/ MW of surplus power, whichever is lower. The maximum amount of subsidy to any one cogeneration project will be limited to Rs 6.0 crores for existing sugar mills.

- For projects selected from cooperative/public sector sugar mills, MNES will provide a grant of up to Rs 2 crores/MW of surplus power fed into the grid, or 50% of the cost of the project, whichever is lower. The grant will be provided to selected financial institutions, namely NCDC, IFCI or IREDA, which agree to provide term loans to the applicant projects for meeting balance of the project costs.
  The grant will be utilized by the financial institutions to provide to the existing cooperative/public sector mills, a capital subsidy of up to Rs 70 lakhs/MW of surplus power, subject to a maximum of Rs 6 crores/project, and a long term soft loan of up to Rs 1.30 crores/MW of surplus power at an interest rate of 9%. The loan component will be repayable to the financial institutions after repayment of their commercial loan. The Ministry's loan component refunded to the financial institution, will have to be utilized by the financial institutions for promotion of cogeneration in the sugar mills in consultation with MNES. A separate corpus will be created by the financial institution for this purpose.
  For new sugar mills (which are yet to start production) subsidies both for cooperative/public sector mills as well as private sector mills shall be half of the levels mentioned above.

- For assistance to cooperative/public sector mills as a necessary condition of the MNES grant, the respective state governments will also have to contribute a fresh equity in the selected mills, of at least Rs 25 lakhs/MW of surplus power.

- Projects taken up in cooperative/public sector mills by independent power producers will also be eligible for support. However in such cases, MNES grant will be on par with private sector projects.

- The projects will be drawn from cooperative/public sector/joint sector sugar mills in various states as follows: Maharashtra; Uttar Pradesh @ two each; Tamil Nadu; Karnataka; Gujarat, Andhra Pradesh ad Bihar @ one each. In case of insufficient response from any of the states, applications may be considered from other sugar producing states, namely Punjab, Haryana, Madhya Pradesh and Orissa.

- The projects will be selected as per criteria which may be laid down by the Ministry which may include among other things, amount of surplus power from the given crushing capacity, cost of the project, cost of generation, period of surplus power generation, innovativeness of the technology and configuration, its replication potential, etc.etc.

- It will be a necessary condition before consideration of applications from cooperative/public sector mills under the scheme, that it should have obtained approval from state government for minimum specified equity participation. After selection, grant will be released only after tie-up of the balance of term loans required for the project and placement of orders for major equipment. For projects in IPP mode, or in the private sector, applications will be considered after approval of the projects by the State Governments, signing of PPA and tie up of balance of financial resources. If selected, disbursals will start only after placement of order for major equipment and commencement of work at site.
  For availing the subsidies the applications in prescribed format (Annexure-I), complete in all respects, as per the provisions of the schemes, should be submitted by the sugar mills to MNES for consideration.

- The Ministry may also decide to award reduced amount of subsidy to any sanctioned project, depending upon the perceived merits of the proposal as a demonstration project, in its sole discretion, to derive maximum advantage out of its budgetary allocations.

- The projects availing of subsidy under the demonstration scheme will not be eligible for benefits under the interest subsidy scheme of the Ministry.

- The eligibility conditions which will have to be fulfilled by applicants applying for subsidy under this scheme are given in Annexure-II. The Terms and Conditions governing the subsidy are given in the Annexure-III and the general terms and conditions are given in Annexure- IV.

2. Modified scheme for interest subsidy to financial institutions that provide terms loans for cogeneration projects

   - Under the scheme, the Ministry will provide grants to IDBI, IFCI, ICICI, NCDC, IREDA, PFC & REC to enable them to reduce interest rates on their term loans for cogeneration projects to eligible sugar mills.

   - For projects generating 4 MW or more surplus power based on bagasse, for feeding into the grid involving change of boiler or turbine, a maximum grant of Rs 35 lakhs/MW of surplus power will be provided, for a loan component of atleast 60% of project cost, and for a project cost of atleast Rs 4 crore/MW of surplus power.

   - For other projects which utilise their existing facilities with minor modification/alterations for generation of 1-4 MW surplus power, and do not involve change of boiler or turbine, a maximum grant of Rs 15 lakhs/MW of surplus power fed to grid will be provided, subject to a loan component of 60% of project cost, and a project cost of atleast Rs 1.5 crore/MW of surplus power.

   - Subsidies will be reduced proportionately in case of lower costs or loan amounts.

- The sugar mills intending to avail the benefits of the reduced interest rates on the term loans should apply to the financial institutions, which after their own appraisal and approval for term loans will submit the application to MNES for the interest subsidy indicating reduction in the interest rates likely to be provided to sugar mills. The applications will be considered by MNES and the subsidy awarded on the basis of overall merit of the scheme as per the criteria which may be load and availability of funds. The application for availing the support, alongwith Detailed Project Report for the project, should be submitted by the financial institution on the request of the project promoters in the prescribed format given in Annexures - I & V.

- Project using second hand boiler or turbine will be provide half the level of grants, subject to project costs of atleast Rs 2 crore/MW of surplus power.

- The eligibility conditions under the scheme are given in Annexure-VI.

- The revised scheme will be effective from 2.9.1996, and will be subject to the Terms and Conditions as given in the Annexure- VII and general terms and conditions given in Annexure - IV.

3. Scheme for financial assistance for preparation of detailed project reports for bagasse based cogeneration projects.

   - Under the scheme, the Ministry will provide financial assistance towards the cost of preparation of Detailed Project Reports for bagasse based cogeneration projects. The pattern of financial assistance is given below :

   - The assistance will be in the form of a one time grant-in-aid to the extent of 50% of the actual cost of DPR, or as per the amounts given below, whichever is lower:

Sl. no.	Broad category of projects	Potential identified	Maximum amount of assistance
1	Projects using 60 bar and higher pressure boilers and incorporating steam/electricity saving measures.	5 MW and above	Rs 4 00 lakhs
2	Projects using 40 bar and higher pressure boilers and incorporating steam/electricity saving measures.	4 MW and above	Rs 3.00 lakhs
3	Projects using boilers with less than 40 bar pressure	Up to 4 MW	Rs 1.00 lakhs

Notwithstanding the above, and the amounts spent on the mill, MNES assistance will be worked out on the basis of normative costs decided by MNES from time to time.

- The DPR should cover, among other aspects, the following aspects :
  - description of the project;
  - mechanical equipment specifications;
  - electrical interfacing equipment specifications;
  - auxiliary equipment specifications;
  - schematics and drawings;
  - bagasse, steam, condensate, cooling water and electricity balances;
  - sources of procurement of major equipment alongwith quotations;
  - costs of each category of equipment and overall cost of the project;
  - training and manpower requirements;
  - financing scheme;
  - cash flow and profitability analysis for 10 years;
  - any other relevant details;
- The application in the prescribed format (Annexure-VIII) for availing support under the scheme should be submitted directly to the Ministry through the respective State Government/State Nodal Agencies/Commissioner of Sugars/SEBs
- The eligibility conditions under this scheme are given in Annexure IX.
- The terms and conditions of assistance are given in Annexure-X and the general terms and conditions in Annexure IV.

General

It may be noted that MNES may decide to increase or decrease the number of projects to be supported or the states to be covered etc., under any scheme, or to not support any project under these schemes, in its sole discretion and without assigning any reason. Further, the Ministry shall in no way be liable for expenditure incurred by mills for pre-project preparation or other activities, merely on the basis of this circular and/or related announcements made by the Ministry.

The aforesaid modified National Programme on Bagasse Based Cogeneration will be subject to any change/modifications, as may be decided by the Government of India from time to time. In case of any dispute on interpretation of any provision under these schemes, the decision of this Ministry shall be final and binding. This Circular is in supercession of all previous circulars on the subject.

The duration of the aforesaid National Programme on bagasse based cogeneration has been extended upto 31.03.2000, or until further orders, whichever is earlier.

This issues with the approval of the competent authority.

J R Meshram
Principal Scientific officer
(For general circulation to all concerned.)

Pricing Policy for Cogeneration: Issues and Options[1]

Sanjeev S Ahluwalia,[2] Pradeep K Dadhich

Transparency 1
Outline

1. Cogen and the economy
   - Role
   - Demand
   - Potential
   - Avoided costs for the economy
   - Stakeholders in cogen
2. Objectives of a cogen pricing policy
3. General principles of a cogen pricing policy
4. Components of a cogen pricing policy

[1] Reproduced as presented at the Conference, with minor modifications.
[2] Tata Energy Research Institute, Habitat Place, Lodhi Road, New Delhi - 110 003, India.

Transparency 2
Determination of Demand for Cogenerated Heat and Power

1. Current demand

- 58 million tonnes (mt) of steam coal equivalent (industry consumption)
- National base load shortage: 8% (capacity 5000 MW)
- National peak load shortage: 15% (capacity 11 000 MW)

2. Drivers of future demand

- Competitive environment to induce cost consciousness
- Increased self-use
- Revenue from sale of cogenerated energy
- Tighter environmental regulation
- Market-based pricing of power and water

Transparency 3
The Potential for Cogenerated Energy

1. Heat energy supply from coal-fired power plants

- 24 mt of coal equivalent (20% of 120 mt coal consumed by power)

2. Cogenerated power

- 15 000 MW in addition to 2000 MW utilized
- 17% of installed generation capacity
- Equals 60% of capacity addition in the Eighth Plan

Transparency 4
Avoided Costs to the Economy from Cogeneration

- Savings on coal consumption of 59 mt
- Reduction in industry: 24 mt/Rs 24 billion (40% of current usage of 58 mt)
- Reduction in power: 35 mt/Rs 35 billion (30% of current usage of 120 mt)
- Release of rail transport capacity of 42 billion tonnes/km (62% of targeted addition of 68 billion tonnes/km over the Eighth Plan; outlay Rs 270 billion)

Transparency 5

Objectives of Cogeneration Pricing Policy: Regulators Viewpoint

1. Short term

   - Cogenerated power capacity: 7000 MW by 2002 (five per cent of total power generation)
   - Utilization by industry of 12 mt coal equivalent of the waste heat from power

2. Long term

   - Integration of investments in cogeneration into the planning process of corporates and utilities
   - Well-developed markets for trading of heat energy and cogenerated power

Transparency 6

Determinants of Price

- Period of contract: minimum 10 years
- Time of supply: peak or off-peak
- Nature of commitment: firm supply or as available
- Severity of damage claims
- Payment terms and arrangements
- Guarantees

Transparency 7

Price Fixation: Cogenerators Viewpoint

1. Baseload type off-take contracts
2. Enforce 'take or pay' rule (utility to pay capacity charges of two-part tariff)
3. Fix price floor at cogenerator's normative *incurred* long-run incremental cost

   - Cost fuel charges at 50% of normative heat rate for coal-fired power.
   - Risk premium at 25 to 50% of risk-less return (interest on government bonds)
   - *As available* sales during off-peak at contract price less risk premium
   - Securitize payments – escrow accounts

Transparency 8

Price Fixation: Utility's Viewpoint

1. Peak-time firm commitments from cogenerators

   - Punitive contractual damages for power interruptions/poor quality
   - Price cap for baseload contracted power at avoided cost of utility
   - Purchase price approach
   - Average incremental cost over planning horizon
   - Long-run marginal cost
   - Specific unit approach
   - Expansion planning approach

Transparency 9

General Principles for Formulating a Pricing Policy for Cogenerated Energy

1. Level-playing field for cogen and independent power producers
2. No administrative intervention in third-party sale contracts

   - Neutral local taxes on self-use and sale

3. User-friendly wheeling and banking policy
4. Regulation to neutralize monopsony

   - Price capped to protect the utility and final consumers
   - Price floor to safeguard the cogenerator/seller

5. Market determination of price in negotiation range
6. Standardize price for small producers (reverse the meter)
7. Progressively tax power and water supply to users with cogen potential

Transparency 10

Generation Costs of Substitutes to Cogenerated Power

Cogen power Rs 0.7/kWh

Social costs	Commercial costs: Lower	Commercial costs: Higher
Lower		• Run-of-river hydro Rs 1.65/kWh
Higher		• Coal: Rs 1.65/kWh • Gas: Rs 2/kWh • Windfarm: Rs 3.53/kWh • Solar thermal: Rs 17/kWh

Regulatory Issues Regarding Pricing Policy and Wheeling and Banking Charges for Cogen Power

S K Mukerjea,[1] Pradeep K Dadhich

Introduction

Contracts for sale of electricity in India are presently governed by Clause 43 of the Indian Electricity Act (1948), together with the amendments issued by the Government from time to time. These amendments are mainly to facilitate the entry of private power producers in power generation. No special provision exists in the Act with regard to the sale of surplus cogenerated power. The political and legal situations, with regard to the sale of cogen power, is somewhat ambiguous, both at the central and the state level Except for two to three state electricity boards (SEBs), no other utility has, so far, made any provision for the wheeling and banking of cogen power. Hence, the formulation of firm guidelines for the sale of cogenerated power is the need of the hour, in the interest of development of cogen power in India. A suitable provision enabling cogenerators to sell at least a specified percentage of their generated power to third-party consumers without obtaining permission from the SEBs will go a long way in attracting investments in the field of cogeneration.

The main issues to be considered in this connection, therefore, are:

- pricing policies for sale of cogen power;
- wheeling of cogen power over existing networks of SEBs – formulation of guidelines for fixing wheeling charges; and
- banking arrangements with utilities – guidelines for fixing banking charges.

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Pricing Policy of Cogen Power

Brief Review of the US Scenario

In the US, under the Public Utilities Regulatory Policies Act (PURPA), it is mandatory that public utilities buy cogen energy on the principle of avoided or marginal costs. Avoided cost is the incremental cost to the utility that will either generate itself or purchase from outside sources. The Federal Energy Regulatory Commission (FERC), however, has not laid down a consistent methodology for its application, and the decision in this regard is left to individual states. This has resulted in a variety of practices being adopted, leading to the pricing of cogen power at rates which bear little resemblance to 'avoided costs'. Another drawback of PURPA is that it forces the utilities to buy cogen power regardless of the reliability and quality of power from this facility, or whether the utility needs the additional capacity. It is seen, therefore, that while PURPA has been instrumental in increasing the quantity of cogeneration (and independent power) in the US, it did not help in the development of efficient non-utility generation because of the government compulsion imposed on the utilities irrespective of their profitability considerations.

However, this distortion in PURPA has been rectified to some extent after the enactment of the Energy Policy Act (EPACT) of 1992. EPACT has broadened the scope of PURPA, and has removed many uneconomic guidelines and restrictions imposed by it which provides for the framework for the ultimate transition to competitive generation. This EPACT is an improvement over PURPA, and has encouraged development of cost-efficient generation by introducing the element of competition in building cogen capacity.

It may, however, be noted that in the US, PURPA is still in force and continues to protect and promote the development of cogen facilities.

Pricing Policy of Cogen Power in the Indian Context

For formulating a pricing policy for cogen power in India, it has to be ensured that the policy should not only be fair to the cogenerator but also to the buying utility, keeping in view the poor financial health of most of the SEBs. Therefore, the viewpoint of both the parties have to be considered. Ideally, from a cogenerator's viewpoint, the utility should:

- pay the cogenerator on the 'avoided cost' principle;
- consider power from cogen sources as firm augmenting utility capacity for meeting base load demands; and
- be ready, therefore, to pay the cogenerator towards both capacity and variable costs.

SEB's Perception

1. Since utilities do not have any experience regarding the reliability of power supply from cogen plants, they would hesitate to recognize this as a source of firm power.
2. Cogen power may not be available during the off-season for the relevant industry.
3. Technical difficulties arise in running small-sized cogen generating units in synchronism with the SEB grid.
4. SEBs are normally in surplus situation off-peak-hours; though they require assistance during peak hours.

Taking into consideration the viewpoints of both the concerned parties, the following pricing structure is suggested for buying utilities.

1. Up to 68% plant load factor (PLF), the price of cogen power should be such as to ensure 16% returns on equity or the cost/unit generated at the SEB's costliest thermal station - whichever is lower.
2. Beyond 68% PLF - during off-peak hours when the SEBs systems are surplus in power, cogen power would have to be sold at competitive rates (which should be lower than the SEB rate).

For direct sale of power by a cogenerator to a bulk consumer, the sales price would have to be at mutually acceptable rates. Some of the factors that would determine pricing would be: reliability and quality of existing supply from the SEB grid vis-à-vis the cogenerator's power supply; degree of reliability of power supply desired by the consumer; importance of continuity and quality of power supply in the manufacturing process of the consumer, etc. Thus, the pricing for third party sales would have to be on a case-to-case basis, taking into consideration the guidelines laid down by the concerned regulatory body in this regard.

Banking of Cogen Power

In an energy banking transaction between two parties, the surplus energy available in power system 'A' is made available to an adjoining system 'B' for their use on the understanding that the same would be returned to them (A) whenever needed. For this service, system A has to pay a banking fee to the system. Such transactions normally cover situations where one of the utilities has spare storage capacity in its hydro reservoirs to absorb surplus thermal energy available in a neighbouring utility. For example, in the northern regional power system of India, the Himachal Pradesh SEB (HPSEB) system has surplus power in summer but runs a deficit in winter. HPSEB banks its surplus power with the neighbouring Punjab SEB (PSEB) system, and draws equivalent energy during winter. This is actually done by a mutual adjustment of the allocated shares of Punjab and Himachal Pradesh in the Bhakra Hydro-electric Project.

The concept of banking is useful in the context of cogen power also. The surplus power with the cogenerator (i.e., the generation available with the cogenerator in excess of the loads of its consumers at a particular point of time) could be supplied to the SEB with the understanding that equivalent energy would be returned when required. For this service, the utility would naturally have to be paid a nominal fee. However, under the power availability shortage conditions in India (which is likely to continue for quite a few years to come), the feasibility of the successful implementation of a banking transaction between a cogenerator and an SEB is rather doubtful. Almost all SEBs are facing power shortage except during night hours. Thus, SEBs would normally be in a position to return the banked energy to the cogenerator only during off-peak periods when the cogenerator would not need energy assistance. Therefore, in case the SEB is unable to honour its commitment to return the banked energy to the cogenerator during the specified hours of the day, the SEB must treat the banked power as power sold to it at a contracted rate and pay the cogenerator accordingly. The duration of agreement for banking transactions should be limited to one year only, which could be renewed on an annual basis.

As regards banking charges, one could consider that the cogen energy banked with the utility goes to meet the load demand of the utility. In other words, a cogenerator 'deposits' energy with the utility on a 'credit' basis which is utilized by the SEB for supplying its consumers. For this, the utility is not required to pay any 'interest' charges. Therefore, one view could be that the cogenerator should not be asked to pay any banking charges. At most, a nominal banking charge of 0.5 to 1% of energy banked (not energy generated) could be levied. Banking period/charges applicable to cogen as per existing guidelines/policies are listed below.

- Tamil Nadu: two per cent of the energy generated for the third party and two per cent for the sister concern within a 25 km radius.
- Karnataka: six per cent of the energy generated for the third party.
- Uttar Pradesh: one year/banking charge not specified.
- Madhya Pradesh: not specified.
- Punjab: not specified.
- Ministry of Non-conventional Energy Sources (MNES): one year/no charges. (guidelines).

Recommended

Recommended banking period/charges:

- Period: one year.
- Charges: 0 5 to 1% of energy banked (not of energy generated).

Wheeling of Cogen Power

Wheeling refers to the transfer by direct transmission or displacement of electricity from the cogen plant to a consumer over the facilities of the host SEB. For this, the cogenerator is required to pay the SEB 'wheeling charges' for making use of the transmission and distribution (T & D) facilities of the host utility. Wheeling charges payable to the host SEB are expected to cover two factors.

- Rental charges for the T & D facilities made available by the SEB.
- Charges to cover the cost of incremental losses due to the superimposition of the cogenerator's power over the SEB's power on the T & D system.

Rental Charges

Annual rental charges payable by the cogenerator to the SEB should be based on the 'annual costs' of the T & D system of the SEB. These 'annual costs' comprise:

- interest and depreciation charges; and
- operational and maintenance and establishment costs.

The representative 'annual cost' of T & D of a typical SEB is about Rs. 587/kW or say Rs 600/kW, i.e , Rs 6 lakhs/MW. Considering a 25 MW cogen plant, the corresponding annual cost for T & D would work out to Rs 150 lakhs As against this, the annual revenue

earned by the cogen plant from sale to the SEB, say at the rate of Rs 1.50/unit (operating at 70% PLF) would be Rs 2300 lakhs/year. Therefore the 'annual T & D charges' as a percentage of the 'annual revenue' earned, works out to Rs 150 lakhs x 100 = 6.5%. It may be noted this figure is indicative, the actual charges may vary from one SEB to another depending on the individual cost and other technical parameters.

Incremental losses

For appreciating the magnitude of the superimposed load of the cogenerator on the SEB system as compared to the size of an SEB system, let us take some concrete figures. The sizes of some of the state SEB systems are listed below.

- Maharashtra: 7000 MW
- Gujarat: 5500 MW
- Uttar Pradesh: 5200 MW
- West Bengal: 2000 MW

It may be appreciated that the injection of a mere 10–20 MW from a cogen plant to an SEB system 150 to 700 times its size would hardly have any effect on the T & D losses (incremental) on the SEB.

As a matter of fact, it is quite possible that the cogen power injected into the grid may actually help in reducing the SEB's T & D loss. This is because the injected cogen power would flow to the intended consumer by the displacement of power flows in the transmission network and not by the physical flow of the cogen power to the intended consumer. It is felt, therefore, that no charges need to be levied by the SEB towards compensating the SEB's incremental losses. Thus, wheeling charges at the rate of about 6–6.5% of the energy wheeled through the SEB system could be considered to be fairly reasonable.

Wheeling charges applicable to cogen as per existing guidelines/practices are as follows.

- Tamil Nadu: two per cent of energy generated for the thrid party and two per cent for the sister concern within a 25 km radius.
- Karnataka: six per cent of the energy generated.
- Uttar Pradesh: 12.5% of the energy generated.
- Madhya Pradesh: two per cent of the energy generated
- Punjab: two per cent of the energy generated.
- MNES (guidelines): two per cent of the energy fed into the grid, irrespective of the distance from generated station.

Conclusion

It is true that all possible encouragement should be given to the cogeneration industry for utilizing the huge untapped cogeneration potential estimated to be of the order of 15 000 MW in the Indian industrial sector. This option offers a commercially attractive alternative to augment the power availability of the SEBs plagued by massive power shortages and a financial crunch as well. The guidelines to be formulated for the pricing

policy, including banking and wheeling charges applicable to cogen sector, should, therefore, take into consideration the interests of both the seller and buyer of the power and should be fair to both the parties. It has to be ensured that the investor on the co-generation sector earns a fair return on his investments. At the same time, although initially the cogenerating sector would need some amount of 'hand holding' by its big brother – the utilities – it is to be remembered that most of the SEBs are on the verge of bankruptcy, and, therefore, their capability of giving support in commercial terms is severely restricted. These factors have to be kept in view while suggesting the guidelines relating to pricing, banking, and wheeling of cogen power that have outlined above.

Session III

Financial and Contractual Issues

Cogeneration in Sugar Industries: Potential and Prospects in India

B S K Naidu[1]

Introduction

India's involvement in the renewable energy movement is now reported to be the second most extensive among the developing countries, second only to China. The growth in this sector can be attributed mainly to the favourable policy and financing environment existing in the country and the concern for the conservation and sustainable development of the environment. Several international development financial institutions like the World Bank (WB), the Asian Development Bank (ADB), and the United States Agency for International Development (USAID) have shown keen interest, and are involved in the financing of renewable energy projects. In order to meet the growing demand for power supply, the Government of India is likely to add around 20 000 MW generating capacity through conventional and 2000 MW through renewable sources including cogeneration, mostly through private sector initiatives, during the Eighth Five Year Plan (1992–97).

India is currently the largest producer of cane sugar in the world, accounting for 10% of the world production. Sugar is a growing industry with the cane area, yield, and recovery of sugar increasing over the decades, though there are cyclical variations from year to year. Though the concept of bagasse-based cogeneration has always been practiced by sugar mills, there has, of late, been growing awareness in the sugar industry of the advantages of installing high efficiency' bagasse-based cogeneration systems. The sugar mills have been further encouraged by favourable policies announced by the Government of India, the state governments, and the various state electricity boards (SEBs).

Cogeneration: The Concept

- Cogeneration is defined as the concurrent generation of process heat and motive power in an industry by the sequential use of energy from a common fuel source; and

[1] Indian Renewable Energy Development Agency (IREDA), Core 4A, 1st Floor, Habitat Place, Lodhi Road, New Delhi - 110 003, India.

depending on the quality of process heat required, it may be based on the topping or the bottoming cycle (see Figure 1).

- In bottoming cycle systems, heat is required for the process at high temperatures and, hence power is generated through a suitable waste heat recovery system.
- On the other hand, in the topping cycle system, heat is required for the process at low temperatures and, therefore, power generation is taken up first. All sugar mills employ this cycle for cogenerating power and heat.

The process of manufacturing crystal sugar requires steam. In existing cogeneration systems, steam is generated in low-pressure boilers by using bagasse – the woody fibrous residue of crushed cane – as fuel. This system was developed when the possibility of export of power to the grid was not envisaged. Further, since the storage of large quantities of combustible bagasse in the premises of the sugar mills was not an advisable option, most of the boilers were designed to use almost the entire quantity of bagasse produced. There is, thus, a 'built-in energy inefficiency' in the sugar factories using all the bagasse as fuel for their low-pressure boilers. By upgrading the steam parameters, the sugar industry can produce electricity far in excess of their own requirement and sell the surplus power to the grid.

Benefits of Adoption of High-efficiency Cogeneration Systems in Sugar Mills

The installation of high-efficiency cogeneration systems results in the following benefits.

- Being no longer dependent on outside power or fuel, sugar mills can be located closer to the cane-growing areas, thus saving on the transportation cost of sugarcane.
- An efficient cogeneration system protects the sugar mill from the vagaries of power supply and the resultant interruptions of the manufacturing process.
- Power generation using bagasse is environmentally cleaner as bagasse produces very little fly ash and no sulphur.

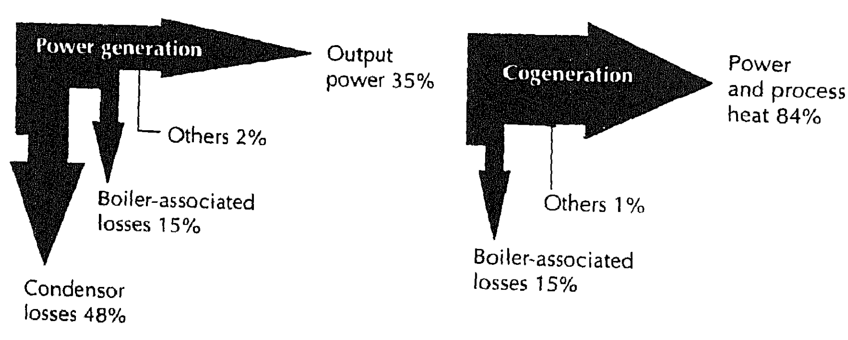


Figure 1. *Cogeneration*

- The net contribution to the greenhouse effect from a bagasse-based cogenerating plant is zero, since the carbon dioxide absorbed by the sugarcane grown, is more than what is emitted by the cogenerating plant.
- A bagasse-based installation has a much lower gestation period (18–24 months) as compared to the 96–120 months required for a coal-based power unit.
- A bagasse-burning unit requires a smaller capital investment and lower recurring costs compared to fossil fuel based power plants.
- Such an unit uses a totally renewable source of energy, which does not involve mining, extraction, and long-distance transportation expenses of fossil fuels.
- The rural location of sugar mills enables cogenerated power to be directly fed to the local sub-station, consequently minimizing transmission and distribution losses and the provision of long feeder lines.
- The adoption of cogeneration systems results in the benefit of quick returns on capital investment.
- No expenditure is incurred for the safe storage and disposal of bagasse.
- A cogeneration plant places no financial or administrative burdens on the sugar factory as it is executed and managed by the management of the sugar factory.
- Power is generated at lower costs in cogenerating systems and pay-back periods are shorter.
- It provides an initiative to sugar mills to concentrate on the conservation of energy and the reduction of steam consumption, thereby improving the profitability of the operation.
- The generation of surplus power in sugar factories is ideally suited for rural electrification and for energizing irrigation pumps and industrial and agro-based units in the villages.
- Even among the renewable energy projects, sugar is perhaps the only sector which has the available infrastructure.

Potential for Bagasse-based Cogeneration: the Indian Sugar Industry

Sugar is produced in 18 states in India. Table 1 gives the state-wise break-up of the 428 Indian sugar mills in the country. November to May is the cane crushing season in India and lasts for an average of 200 days. Per day the size of sugar plants in India, in terms of cane crushing capacity, varies from 1250 tonnes of cane to 5000 tonnes of cane crushed per day (tcd) and above. The minimum size of a sugar mill has now been stipulated at 2500 tcd. Table 2 gives the state-wise break-up of sugar mills in India based on their licensed cane crushing capacity

A typical sugar mill has the following features.

- Bagasse produced by crushing cane is 30–35% of the cane crushed
- Bagasse is burnt to generate steam in boilers. The steam pressures encountered range from 15 kg/cm^2 in old plants, 21 kg/cm^2 in plants installed in the 70s, and 32 to 43 kg/cm^2 in mills installed since the mid-80s.
- Operating at low pressures, the mill can use almost the entire bagasse for generation of process steam thereby avoiding accumulation of bagasse and eliminating the need to make provisions for its storage and disposal.

Table 1

Statewise sectoral break-up of sugar mills in India

State	Joint sector	Public sector	Cooperative sector	Total
Uttar Pradesh	44	35	31	110
Maharashtra	5	—	104	109
Andhra Pradesh	10	8	18	36
Tamil Nadu	14	3	15	32
Karnataka	11	3	17	31
Bihar	14	15	—	29
Gujarat	—	—	19	19
Punjab	4	—	15	19
Haryana	1	—	10	11
Orissa	7	—	1	8
Mahdya Pradesh	2	3	3	8
Kerala	1	1	2	4
Rajasthan	1	1	1	3
Assam	1	1	1	3
West Bengal	1	1	—	2
Pondicherry	1	—	1	2
Nagaland	—	1	—	1
Goa	—	—	1	1
Total	117	72	239	428

Table 2

Capacitywise break-up of sugar mills in India (tcd)

State	≤1250	<2500	2500	<5000	>5000	Total
Uttar Pradesh	44	18	29	12	7	110
Maharashtra	44	18	26	15	6	109
Andhra Pradesh	22	4	6	1	3	36
Tamil Nadu	6	7	13	4	2	32
Karnataka	15	5	6	1	4	31
Bihar	15	10	3	0	1	29
Gujarat	7	1	4	3	4	19
Punjab	6	2	9	1	1	19
Haryana	5	2	3	0	1	11
Orissa	5	0	3	0	0	8
Madhya Pradesh	7	1	0	0	0	8
Kerala	3	0	0	0	0	3
Rajasthan	2	1	0	0	0	3
Assam	3	0	0	0	0	3
West Bengal	2	0	0	0	0	2
Pondicherry	1	1	0	0	0	2
Nagaland	1	0	0	0	0	1
Goa	1	0	0	0	0	1
Total	189	70	102	37	29	427

- The ratio of process steam consumption is 50–55% of the cane crushed.
- Mill-wet bagasse contains about 50% moisture – (48–52%). The gross calorific value of mill-wet bagasse (50% moisture) is 2280 kcal/kg. The proximate and ultimate analysis of mill-wet bagasse is given in Table 3.

Cogeneration Potential in India

A number of studies have been conducted to estimate the potential for bagasse-based cogeneration in India. The results of some of the more recent studies are given below.

- In 1993, a Ministry of Non-Conventional Energy Sources (MNES) taskforce, formed to study the potential of bagasse-based cogeneration, estimated the potential at 3500 MW.
- The Tata Energy Research Institute, on the other hand, has estimated India's potential for cogeneration in sugar mills as 5100 MW.
- A third study conducted by USAID/Winrock International/IDEA Inc., in May 1994, reported that efficient cogeneration could yield an additional 3800 MW of electric power.
- The most recent estimation was made by an IFREE/dLA/IDS team, who have estimated the potential as 2800 MW with highly efficient mill operations and high pressure conditions.

Bagasse-based cogeneration, however, has the major drawback – the annual production period is usually limited to six to seven months. This period does not normally match the seasonal variation in electric load demand. The bagasse availability period coincides with the surplus hydel peaks in some states, while in the peak summer months, sugar factories are shut down due to non-availability of cane. This constraint may be circumvented by generating electricity all through the year, using available bagasse or by resorting to other fuels in the off-season.

Possible Models of Cogeneration

A few possible configurations recommended by the MNES taskforce for designing a cogeneration system in new plants are listed below. For existing plants, there are a number of options which are to be worked out on a case-to-case basis incorporating energy conservation measures.

Table 3
Analysis of mill-wet bagasse

Proximate analysis (%)	Ultimate analysis (%)
Fixed carbon – 11 5	Carbon – 22 5
Volatile – 37	Hydrogen – 3 0
Moisture – 50	Oxygen – 23 0
Ash – 1 5	Ash – 1 5
	Sulphur – traces

Extraction cum back Pressure Route

The main features of this configuration (Figure 2) are listed below.

- The sugar factory produces only as much steam as is needed for its process.
- By upgrading the steam parameters, surplus power is produced after meeting captive requirements.
- Surplus power production is envisaged only during the crushing season.
- This is the cheapest option from the point of view of initial cost and efficiency of the system.
- This turbine, however, has the disadvantage that the fluctuations in surplus power supply is related to the fluctuations in cane supply, process steam demand, etc.

Extraction and Condensing Route through the Bagasse Fuel System

This system (Figure 3) has the following features.

- The sugar factory produces steam by using the entire quantity of bagasse produced during the crushing season.
- By using an extraction and condensing turbine, surplus power production can be extended during the off-season by operating the turbine in the condensing mode.
- Power can be generated by using bagasse bought from nearby non-bagasse using sugar mills or by using bagasse left over during the latter part of the crushing season.
- The capital cost is higher for this option.
- This system ensures the supply of stable surplus power during the crushing season thereby reducing fluctuations in sugar plant operation.

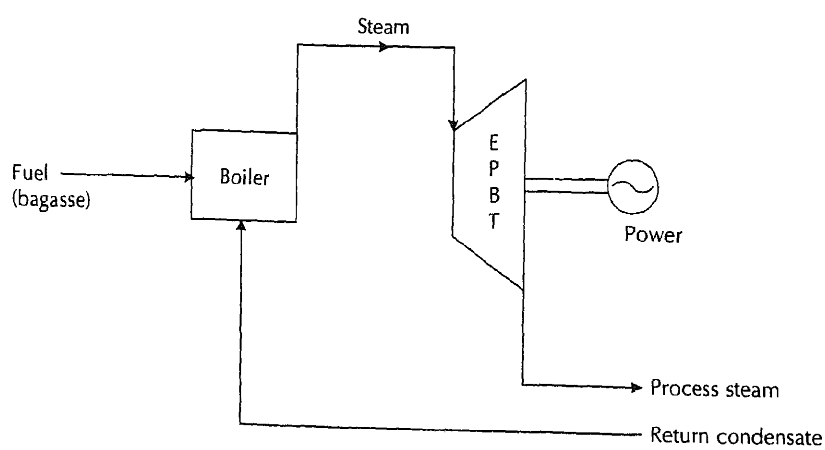


Figure 2. *An extraction cum back pressure turbine (EPBT)*

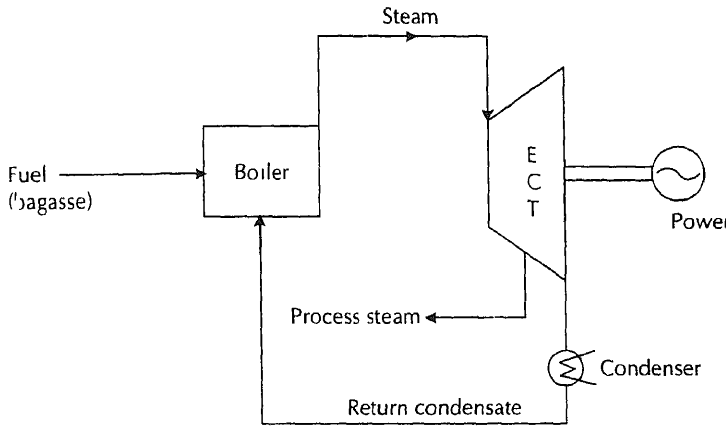


Figure 3. *An extraction and condensing turbine (ECT)*

Condensing Route based on Dual Fuel System

This option (Figure 4) has the facility of ensuring a year-round, stable surplus power supply through the use of a support fuel. It's main features are listed below.

- This is a viable option for sugar mills located near a source of secondary fuel.
- In such an option, the reliability of alternate fuel supply has to be ascertained. Design aspects of the boiler also need to be examined to ensure availability of a suitable furnace capable of multi-fuel combustion, particularly the combination of bagasse and coal/lignite.

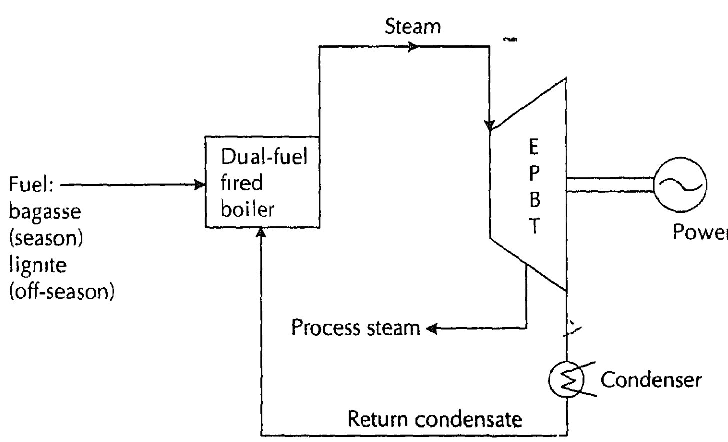


Figure 4. *The condensing route based on the dual fuel system*

- The capital cost of multi-fuel systems, particularly those using coal as support fuel will be high in addition to the connected considerations of pollution control and ash disposal.
- Highly skilled manpower is required for the operation and maintenance of such an advanced technology.

In addition to the options outlined above, the following simple energy conservation measures, if adopted, can contribute to surplus power generation.

- Replacement of turbo drives used for cane preparation and milling with hydraulic or electric drives.
- Reduction of process steam consumption from the existing level (50–55% on cane) to 42–45% by the incorporation of modifications in the juice heating and evaporation system.
- Increasing the efficiency of boiler operations from the existing average of 60% to at least the minimum stipulated value of 70%.
- Introduction of more controls and instrumentation in power plant operations.
- Use of bagasse driers to reduce the moisture content in bagasse before it is burnt in the boiler.

In order to derive the maximum power from a cogeneration system, it would be necessary to ensure maximum energy economy and optimum system configuration. This would also ensure high efficiency at minimum costs and adequate safety. Modular standardization of capital equipment and reuse of displaced capital plant elsewhere can substantially reduce the cost of upgrading cogeneration in the existing plant.

MNES Taskforce for Biomass-based Cogeneration

MNES had constituted a taskforce of experts in August 1993 to formulate government policy for a national programme on biomass-based cogeneration. The taskforce, which deliberated on issues of potential, technologies, and constraints, identified a potential of 3500 MW of surplus power which could be generated from sugar mill bagasse. It recommended that the following steps be taken by the government to propagate cogeneration in the Indian sugar industry.

1. Announcement a policy on:
    - fiscal/financial incentives for cogeneration systems; and
    - subsidies/grants for demonstration projects.
2. Formulation of norms for cogeneration schemes which would be eligible for incentives.
3. Formulation of standard procedures for the calculation of the rate of return and the selling price of power from cogeneration plants, keeping in view the opportunity costs of bagasse, the costs, if any, of supplementary fuels, and minimum capacity utilization.

4. Formulation of a model agreement with state utilities to take power from sugar industry cogeneration.
5. Evolving means of compensating cogeneration schemes where the price of power offered by the state utilities does not give minimum 16% post tax return on equity.
6. Appointment of suitable agencies to do a detailed state-wise survey to assess cogeneration potential and shortlist prospective mills for demonstration projects.

National Programme on Bagasse-based Cogeneration

Based on the recommendations of the taskforce, MNES launched a National Programme on Bagasse-based Cogeneration in January 1994. The main objectives of the programme are outlined below.

1. Creation of conditions conducive for the adoption of high-efficiency cogeneration schemes in the Indian sugar industry, leading to the early exploitation of the estimated potential of around 3500 MW for surplus power generation
2. Development of indigenous capability for, and capacity of, design, manufacture, and operation of modern high-efficiency cogeneration plants.
3. Generation and supply of 300 MW of power through bagasse-based cogeneration in the Indian sugar industry during the Eighth Plan.

The major components of the programme are listed below.

1. Non-recurring capital subsidy (up to 30% of the equipment cost or up to Rs 70 lakhs/MW of net surplus power, whichever is lower) for projects that envisage the generation of at least 5 MW of surplus power using boilers which generate steam at a pressure of 60 bars or higher. However, the maximum amount of subsidy to any cogeneration project will be limited to Rs 60 million in case of existing sugar mills. In case of new sugar mills, the subsidy will be at half of the above-mentioned levels. A maximum of 12 demonstration projects are proposed to be taken up in sugar mills in the major sugar-producing states in the country. Out of the 12 projects planned to be supported under the programme, nine will be in the cooperative/public sector. The projects will be taken up in those states which have announced a general policy for purchase of the surplus power generated
2. Soft semi-commercial loans are proposed for projects which envisage production of at least 4 MW of surplus power. Under this activity, MNES will provide grants (up to a maximum rupees of 20 lakhs/MW of surplus power) to financial institutions like the Industrial Development Bank of India (IDBI), the Industrial Finance Cooperation of India (IFCI), the Industrial Credit and Investment Corporation of India (ICICI), the National Cooperative Development Cooperation (NCDC), IREDA, etc., to enable them to reduce interest rates by two per cent on their lending (up to 60% of the project cost) to eligible sugar mills.
3. Assistance in the form of grants to the extent of up to 50% of the cost of preparation of detailed project reports, subject to a maximum of Rs 4 lakhs.

4. Support to R & D projects in the areas of bagasse drying, bagasse storage and baling, fluidized bed combustion, and gasification of bagasse.
5. Support to information dissemination, and to training and assessment studies.

Under the National Programme, the sugar mills listed in Table 4 have been sanctioned an 'in principle' subsidy for surplus power cogeneration.

IREDA's Role in Promoting Bagasse-based Cogeneration

IREDA has been entrusted with the responsibility of promoting bagasse-based cogeneration as part of a renewable energy development progamme. In addition to this, IREDA also finances cogeneration projects based on other biomass fuels. The norms of financing under this programme are as shown in Table 5.

IREDA is presently being appraised by ADB for a US $150 million line of credit for various renewable energy technologies including bagasse-based cogeneration. IREDA has also commissioned an all-India study on bagasse-based cogeneration through the Maharashtra Industrial & Technical Consultancy Organization (MITCON), Pune. The key issues to be dealt with in the study include generation of a project pipeline for IREDA by identification of sugar mills with the potential for surplus power generation using bagasse and the identification and evaluation of key issues of bagasse-based cogeneration projects for the quick and successful implementation of such projects.

Table 4
Projects Sanctioned under the National Demonstration Programme

Name	Mill capacity (tcd)	Net exportable power (MW)	Subsidy amount (Rs in lakhs)
EID Parry (I) Limited (Tamil Nadu)	5000	10.76	450 25
Kothari Sugars & Chemicals Ltd (Tamil Nadu)	3500	9 90	268 35
Malaprabha Cooperative Sugar Mill (Karnataka)	3500	18 10	600 00
Thiru Arooran Sugar Limited, Tamil Nadu (Unit 2)	2500	9.20	343 00

Table 5
IREDA's norms of financing

Norm	Provision
Minimum promoters contribution	25%
Term loan	Up to 75% of project cost
Interest rate (inclusive of interest tax)	16 5%
Total repayment period (inclusive of moratorium)	10 years
Moratorium (maximum)	3 years

Private Power Environment in India

The Government of India has targeted a capacity addition to the extent of 2000 MW through renewable energy including 300 MW through bagasse-based cogeneration. In order to achieve this target of power generation, the Government has announced several measures to promote independent power production. These include:

- up to 100% foreign equity participation;
- flexible power sales arrangements in which private power companies can act as licensees, supplying and distributing power to a given region or as generating agencies supplying power to the grid at large;
- 4:1 debt–equity ratio on investments;
- single-window clearance through a new investment promotion cell;
- return on investment of 16% based on 68.5% plant load factor (PLF),
- a 30-year initial investment period, with subsequent extensions for 20 years; and
- a five-year tax holiday, with a partial holiday through to the 10th year of the project.

Fiscal Incentives by the Government of India

The Government of India has offered various incentives to this sector. These are listed in the Table 6.

State Government Policies for Cogeneration

Table 7 gives a summary of the incentives offered by various state governments in India.

Table 6
Incentives offered by the Government of India

Item	Description
Income tax depreciation	100% depreciation in the first year can be claimed for the following cogeneration equipment· • fluidized bed boilers, • back pressure, pass-out, controlled extraction, extraction and condensing turbines for cogeneration along with boilers; • high-efficiency boilers, and • waste heat recovery equipment
Tax holiday	First five years nil, next five years 70%
Customs duty	Duty leviable for (NRSE) power projects of less than 50 MW capacity (under project import category) is 20% *an valorum*, this covers machinery, and equipment component parts required for generation of electric power
Central excise duty	Exempted for renewable energy devices, including raw materials, components, and assemblies
Central sales tax	-do-
General sales tax	Exemption is available in certain states

Table 7

State government policies and incentives for bagasse-based cogeneration

Description	MNES guidelines	Tamil Nadu (TN)	Karnataka (K)	Maharashtra (M)	Uttar Pradesh (UP)	Madhya Pradesh (MP)	Punjab (P)
Power wheeling charges	Two per cent of the energy fed to the grid, irrespective of the distance from the generating station	Two per cent of energy generated for the third party and two per cent for sister concerns within a 25 km radius	Six per cent of the energy generated for the third party (likely five per cent)	Nil	12 5% of energy generated	Two per cent of the energy generated	Two per cent of the energy generated
Power banking period/charges	One year/nil	Two per cent of energy generated	Six per cent of the energy generated	—	One year	Not specified	Not specified
Buyback rate by SEB	Rs 2.25/kWh (minimum) with five per cent escalation without any restriction on time or quantum of electricity supplied	Rs 2 25/kWh, with five per cent escalation every year for five years	Rs 2 25/kWh	Rs 2/kWh for export up to 4 MW, Rs 2 25/kWh for export above 4 MW (these rates to remain in force for six years)	Rs 2 25/kWh or at a rate which ensures a RoE of 16% and 68 5% PLF, whichever is lower	Rs 2 25/kWh	Rs 1 50/ kWh
Third party sale	Allowed to high tension (HT) consumers within the state at mutually agreed rate	Allowed to HT consumers at mutually agreed rates	Allowed	Not allowed	Allowed to HT consumers at mutually agreed rate within a radius of 5 km	Allowed to HT consumers at mutually agreed rates	Allowed at mutually agreed rates
Other concessions	• Exemption from electricity duty • Exemption from demand cut up to 30% of installed capacity • Sales tax benefits applicable to new industrial units • Infrastructural facilities similar to industrial estates	Exemption from electricity generation tax	Exemption from electricity tax for 5 years for captive use (other modes –04p per unit)	—	Nil	• Exemption from electricity duty for five years • Demand cut up to 30% of installed capacity • Exemptions from sales tax and other concessions applicable to new industry	• Exemption from electricity duty • Demand cut up to 30% of installed capacity • Exemptions from sales tax and other concessions applicable to new industry
Promotional agency		TNEB	KSEB	MSEB	NEDA	MPUVN	PSEB

Current Cogeneration Activities in India

Cogeneration activities in Indian sugar mills were restricted to the production of power required for captive use in the sugar mill and steam for the sugar production process. Since the late 1980s, there has been an increasing awareness of the advantages of surplus power generation from sugar factories, and some of them have taken steps to install medium pressure boilers (42 kg/cm^2) to generate surplus power for feeding their ancillary units or the state grid.

Two such sugar mills are the Daurala Sugar Works, Uttar Pradesh, and the Shree Datta Sehkari Shakkar Karkhana, Maharashtra; they have been exporting nearly 1.5 MW of surplus power to nearby industrial units. Two other sugar mills in the cooperative sector in Tamil Nadu (the M R K Cooperative Sugar Mills and the Sethiathope and Cheyyar Cooperative Sugar Mills, both of 2500 capacity) have installed cogeneration plants with a power generating capacity of 7.5 MW in their premises. These sugar mills have been designed to export nearly 4 MW of power to the SEB grid.

The sugar mills which have commissioned bagasse-based cogeneration plants with provisions for export of surplus power are listed in Table 8.

Multilateral Investment Programmes

USAID is presently operating a US $19 million, five-year greenhouse gas pollution prevention project, which is considered a part of the US contribution to the Global Environment Facility. The project aims at reducing greenhouse gas emissions by catalysing the development of efficient coal and alternative bagasse/biomass energy approaches in India for power sector expansion within India's economic development programme. The project is meant to promote efficient power technologies that have not been demonstrated in India, and has two major parallel components:

- efficient coal conversion (ECC); and
- alternative bagasse cogeneration (ABC).

Table 8

Bagasse-based cogeneration projects exporting surplus power (as on December 1995)

Name	Year of commissioning	Exportable Power (MW)
M R K Cooperative Sugar Mill Ltd (Tamil Nadu)	1992/93	3 00
Cheyyar Cooperative Sugar Mill Ltd (Tamil Nadu)	1992/93	3.00
Shri Datta SSK Ltd (Maharashtra)	1992/93	1.50
Shri Jawahar SSK Ltd (Maharashtra)	1994/95	1.50
Deogiri SSK Ltd (Maharashtra)	1994/95	1 50
Dhampur Sugar Mills Ltd Unit (Uttar Pradesh)	1994/95	1.50
Thiru Arooran Sugar Ltd; (Tamil Nadu)	1995/96	8.00
Total capacity achieved	—	20.00

This programme has a project investment component of US $12 million and a technical assistance component of US $7 million. The ABC programme focuses on options for off-season power generation in sugar mills, so that they can supply firm power round the year. The highlights of the ABC investment component of US $9 million, meant to buy down the cost of the commercial line to be established by IDBI are outlined below.

- It aims at the demonstration and commercialization of bagasse-based cogeneration plants that rely on supplemented biomass fuels rather than on fossil fuels. The biomass fuels recommended are canefield residues; stored bagasse (which has been saved by the adoption of energy-conservation measures); biomass, such as rice husk, rice straw, groundnut shells, etc.; and wood from energy plantations
- This component will work closely with the sugar industry to provide the industry with information, technical assistance, and training on all feasible options
- The component will also cover the incremental costs and risks associated with the initial adoption of technologies and development of skills and knowledge needed for the introduction and use of supplemental biomass fuels by bagasse cogeneration systems.
- The ABC projects will have a debt–equity ratio of 3:2.

The objective of the ABC technical assistance component (US $3 million) is to provide the pre-investment support needed to help stimulate private sector investment in biomass/bagasse-based cogeneration projects.

In addition to the above project, ADB is also in the final stages of firming up a US $150 million aid for financing renewable energy projects including US $65 million for cogeneration in India for on-lending through IREDA. The loan programme is expected to commence in April 1996. As part of developing a financing programme, IREDA signed a memorandum of understanding with ADB to carry out studies in specific renewable energy sectors. The study has been carried out at a cost of US $371 000, including a contribution of US $354 000 from the bank.

Conclusion

Several studies carried out on the subject have established that significant potential exists in India for bagasse-based cogeneration. Further, the interest shown by the Government of India, the state governments, and international funding agencies has provided the necessary thrust to encourage sugar mills to become increasingly aware of the need for energy conservation and the need to venture into the area of high-efficiency cogeneration leading to the export of surplus power. As one of the largest processors of cane sugar, the industry is on the threshold of making a noticeable start in the power generation sector.

Financing Structures for Cogeneration Plants

Rajeev Suri[1]

Introduction

The objective of this paper is to describe broadly the ownership structures available for financing cogeneration projects in India. It also illustrates the suitability of certain modes of financing over others, and the critical issues that should be examined before arriving at a decision. Specifically, the issue of choosing between loan and lease financing is discussed using an illustration. Finally, some of the recent changes introduced by the 1996/97 budget are discussed, which are likely to have a bearing on the financing prospects for cogen plants.

Ownership Structures for Cogen Plants

In determining the choice of the ownership structure for a plant, user needs and considerations have to be kept in mind. Definition of these needs and issues of consideration is a process which has technical, legal, and financial aspects. Broadly speaking, the ownership to a facility can take the following forms:

- direct ownership by the user;
- lease of the cogen facility by the user (the lease may be a financial lease or an operating lease); and
- purchase of power from an outside operator, based on a power purchase contract between the user and the operator.

The three structures are represented diagramatically in Figures 1, 2, and 3. The figures also describe the responsibilities of the parties involved in the transaction. Some of the critical issues which determine the choice of the ownership structure are listed below.

[1] KOTAK Mahindra Finance Ltd, 502, Antriksh Bhavan, 22 Kasturba Gandhi Marg, New Delhi - 110 001, India.

- Utilization of capital.
- Balance sheet leverage.
- Cost of power.
- Fuel supply risks.
- Degree of control over output of plant.
- Sticking to one's core business.

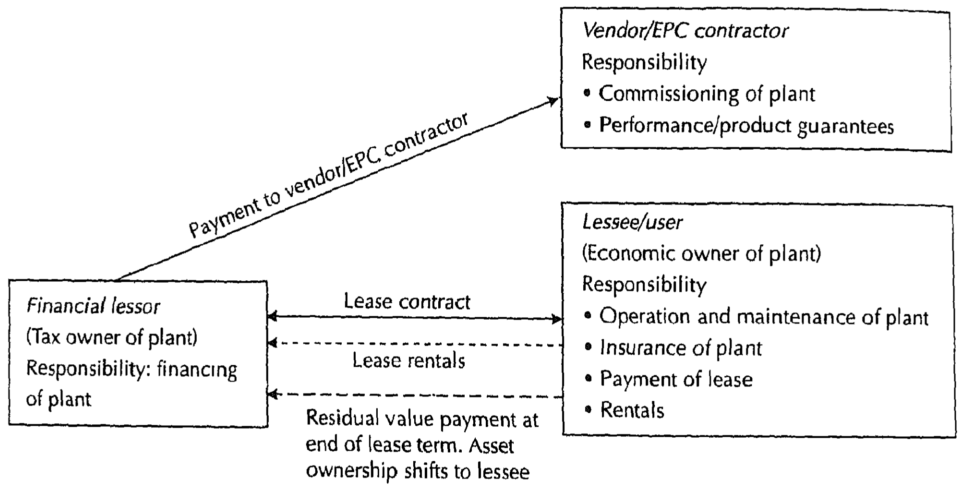
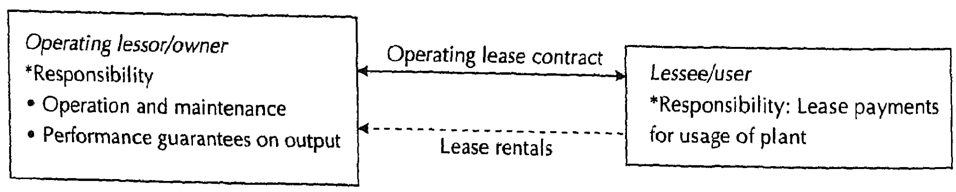


Figure 1. *Financial lease*



*Specific responsibility will be defined in the operating lease contract. The responsibilities described above typical.

Figure 2. *Operating lease*

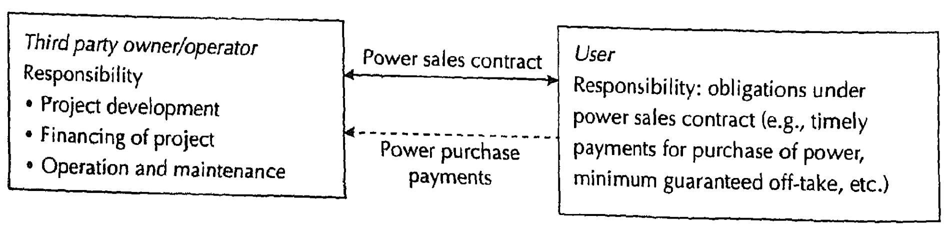


Figure 3. *Outside operator*

The direct ownership of the cogen facility involves financing the plant through a mix of debt and equity capital on the owner's balance sheet. The leverage of the balance sheet is increased to the extent that debt is added to the balance sheet. In the case of a lease, however, no capital is utilized, since most leases provide 100% financing. Most operating leases also do not require commitments of capital. The same is the case when the cogen plant is owned and operated by an outside operator.

The ownership structure also affects the various risks that a user faces or the degree of control that the user enjoys on the cogen facility. Fuel supply risks and operation and maintenance (O & M) risks are higher for a self-owned plant than for a plant which is operated by an outside party and is obligated to a certain guaranteed output. The cost of power is likely to be higher in case of the power purchased from an outside operator than from a self-owned plant, or from a plant taken on an operating lease.

Another consideration is the philosophy of the company towards the ownership of a facility or business which is unconnected with its core business or its area of expertise. Most companies in India have financed such plants on their balance sheets and maintain staff which are involved in the O & M of such facilities. On the other hand, a company might like to stick to its core business, and not get involved in the construction and O & M of the plant. However, the trend in India, so far, has been to set up cogen plants in the company's books and operate it in a manner no different from the company's existing core business. Reasons for this include the absence of a well-developed institutional framework for access to non-recourse project finance in India, and the absence of operating lessors of such plants in India so far.

The magnitude of costs and risks attached to each ownership structure are specific to a user's circumstances, and each user has to define key issues while choosing an ownership structure.

A hybrid structure of the 'outside operator' approach and the self-ownership approach is for the user to form a special purpose vehicle (SPV) to finance the cogen project. The main objective of taking the SPV route is to isolate the cash flows of the cogen facility from the parent company's cash flows, so that the project can be evaluated on a stand-alone basis or on a non-recourse or limited recourse basis, rather than on the basis of the parent company's cash flows or profitability of its businesses. The SPV route also offers the following advantages.

1. It becomes possible to introduce outside equity investors in the project. This is not possible if the project is capitalized in the parent company's books.
2. The leverage and credit rating of the parent company remains unaffected with the lenders, if the SPV has been financed with non-recourse debt. It may be affected to the extent credit support in the form of guarantees have been extended by the parent company to lenders to the SPV.

The parent company can focus on its core business. The extent to which it needs to control the operation of the cogen facility will determine its equity ownership in the facility. Thus, the SPV may, on one extreme, be a 100% subsidiary of the parent company, and, on the other, have only a minority equity representation from the parent company. The extent to which the parent needs to exercise control will be the chief determinant of the parent's equity holding in the SPV.

It is possible that the SPV might have a better credit rating than the parent company

itself. For instance, the SPV may have a power sales contract with multiple buyers (the parent being one of the buyers) with strong credit rating and absolutely watertight fuel supply and O & M agreements with credible contractors. In such a case, the merits of the project might enable the SPV to raise debt at a cheaper rate than the parent company can raise debt.

Choice of Financing for Cogen Plants

Whatever be the ownership structure chosen, the financing of the plant can be done through a mix of debt and equity. The choices available for leveraging one's equity include:

- loans from financial institutions and banks;
- financial lease; and
- debts placed with investors, which includes financial institutions and banks.

As cogen plants are eligible for 100% depreciation under the Income Tax Act of 1961, leasing of such plants is attractively priced by financial lessors. Financial leasing has been the preferred means of financing for many plants, especially by users who are in a low tax-paying category. This section examines various issues related to the choice between loan and lease financing. For the purposes of the discussion, financing through loans and financing through placement of debt instruments is treated as the same mode, since the terms of such finance are typically similar.

Leases: Operating and Financial

A financial lease is a pure financing transaction where the lessee pays, to the lessor, lease rentals over the period of the lease. This includes the return of the principal with interest. The lease period in a financial lease is always fixed and non-cancelable. Typically, the financial lease comes with an option to the lessee to purchase the asset at the end of the lease period at a bargain price. This option is always exercised by the lessee, since the lessee has, by the end of the lease period, paid for almost the entire cost of the asset with interest. The intention in an operating lease is the use of an asset and not its eventual ownership or financing. Unlike a financial lease which is basically a financing transaction and has a fixed non-cancelable period, called the primary period, during which the lessor recovers his principal with interest, the lessee in an operating lease has an option to cancel the lease after a certain period of time to take care of various risks, for instance, the risk of obsolescence or breakdown. Operating leases are common with assets such as computers, cars, and aircrafts, where the lessee does not want to own the asset permanently, but only wants to use the asset for a period of time. Operating lessors are normally manufacturers of such assets or lessors who specialize in leasing a particular type of goods (aircrafts, power plants, etc.), and, typically, know more about managing the risks of obsolescence, breakdown, etc., than the user.

Conceptually speaking, the operating lease rental will be more expensive than the financial lease since the lessor is taking not only credit risk, which is the risk of non-payment or delay in the lease rentals, but also the asset risk – the risk of obsolescence, breakdown, etc. Rather than face the risk of technological obsolescence or breakdown,

lessees in operating leases prefer paying a higher lease rental, where they have a right to cancel the lease any time, or after a certain period of time, by paying a cancellation charge. It is the superior knowledge of the operating lessor about the asset or the asset market which enables the lessor to offer an operating lease. A number of cogen plants in India are trying to popularize the idea of operating leases. Companies such as Thermax Ltd and Western Paques are pioneers in this field and have been selling this idea with the use of pilot plants.

Choice between a Loan and a Financial Lease Option

The critical question here is whether a user should go in for a lease finance option or a loan. The key decision parameters to be considered while making this choice are discussed below.

The current and future tax status of the lessee and lessor is by far the most critical parameter. Financial leases can be priced optimally only when the tax status of the lessee and the lessor differ, that is, when one of them is in a high tax-paying category and the other in a zero or low tax-paying category. This enables the lessor, taking the benefit of the tax depreciation, to pass on part of this benefit to the lessee by way of cheaper lease rentals. The depreciation in the books of the lessee would not have yielded any tax benefits since the lessee is in a low or zero tax-paying category.

A cogeneration plant is eligible for 100% depreciation under the Indian Income Tax Act 1961. This translates into a substantial tax saving for a company which owns such a plant on its books and can utilize this depreciation to reduce its tax outflow. However, a number of companies cannot utilize the depreciation available to them, either because of past accumulated losses, unutilized depreciation, ongoing capital expenditures which will result in more than adequate future tax shields, etc. To such companies, this tax depreciation is useless and a financial lease will make much more sense since a tax-paying lessor has use for the tax shield that depreciation provides and is willing to pass on part of this benefit by way of cheaper lease rentals. The pricing of such leases is such that the leases are substantially cheaper than loans. Companies such as Prakash Industries Ltd, JK Corporation Ltd, JK Industries Ltd, Simbhaoli Sugar Mills Ltd, etc., have taken advantage of their zero tax status and financed their captive/cogen plants on a lease finance basis. The lessors in such cases have been tax-paying corporates looking for tax shelter. To illustrate how important the tax status is as a parameter, which affects the choice between lease financing and debt financing, we have taken four different scenarios.

- *Scenario 1*. Lease option for a tax-paying corporate (Table 1)
- *Scenario 2*. Lease option for a zero tax corporate (Table 2)
- *Scenario 3*. Loan option for a tax-paying corporate (Tables 3a and 3b)
- *Scenario 4*. Loan option for a zero tax corporate (Tables 4a and 4b)

The following assumptions have been made.

- Total capital expenditure required is Rs 1000. The entire capital expenditure is a one-time expenditure.

Table 1

Financial lease option: tax-paying corporate

Quarters	Lease rent	Post-tax lease rent	Depreciation	Depreciation benefit lost	Post-tax cashflow
1	—	—	—	—	1000
2	-63	-35.91	—	—	-35 91
3	-63	-35.91	—	—	-35.91
4	-63	-35.91	—	—	-35.91
5	-63	-35.91	1000	430	-465 91
6	-63	-35.91	—	—	-35 91
7	-63	-35.91	—	—	-35.91
8	-63	-35 91	—	—	-35.91
9	-63	-35.91	0	0	-35.91
10	-63	-35.91	—	—	-35 91
11	-63	-35.91	—	—	-35.91
12	-63	-35.91	—	—	-35 91
13	-63	-35.91	0	0	-35.91
14	-63	-35.91	—	—	-35.91
15	-63	-35.91	—	—	-35.91
16	-63	-35.91	—	—	-35 91
17	-63	-35.91	0	0	-35.91
18	-63	-35.91	—	—	-35.91
19	-63	-35.91	—	—	-35 91
20	-63	-35.91	—	—	-35.91
21	-63	-35 91	0	0	-45.91

Note Depreciation rate· 100%; capital expenditure. Rs 1000, lease rental Rs 63 per 1000 of capex per month, residual value: one per cent; and net present value @ 16%· = Rs 473 36

- Corporate income tax rate is 43%.
- Rates taken for lease and loans are current rates prevailing in the market.
- In case of loan evaluation, a margin of 25% has been taken and a cost of equity has been assumed to be 20% post-tax. The equity component is refunded at the end of the 20 quarters.

The terms of the lease include:

- provision of 100% financing;
- rentals payable quarterly in arrears for 20 quarters;
- rate of rental at Rs 21 per thousand per month (ptpm) of asset cost for 100% depreciable assets (cogen plants);
- residual value payable by lessee at one per cent of original asset cost;
- pre-tax internal rate of return (IRR) of the lease (100% depreciation) at 9.3% p.a.;
- rate of rental for assets attracting 25% depreciation at Rs 26 ptpm of asset cost, and
- pre-tax IRR of lease (of 25% assets) at 19% p.a.

Table 2

Financial lease option–zero tax corporate

Quarters (initial capex = 1000)	Lease rent	Post-tax lease rent	Cash flows
1	—	—	1000
2	–63	–63	–63
3	–63	–63	–63
4	–63	–63	–63
5	–63	–63	–63
6	–63	–63	–63
7	–63	–63	–63
8	–63	–63	–63
9	–63	–63	–63
10	–63	–63	–63
11	–63	–63	–63
12	–63	–63	–63
13	–63	–63	–63
14	–63	–63	–63
15	–63	–63	–63
16	–63	–63	–63
17	–63	–63	–63
18	–63	–63	–63
19	–63	–63	–63
20	–63	–63	–63
	–63	–63	–73

Note Depreciation rate = 100%, capital expenditure = Rs 1000, lease rental = Rs 63 per 1000 of capex per month, residual value one per cent of capex, and net present value @ 16% = Rs 539 63

The terms of the loan are listed below.

1. Financing is available; 25% has to be brought in as equity (margin).
2. Principal repayment is in 12 equal quarterly instalments starting from Year 3 to Year 5.
3. Interest at the rate of 21% per annum is payable quarterly in arrears on the principal outstanding at the end of the quarter.

Net present values (NPV) of the four scenarios are computed and the results are ar-ived at based on the calculations shown in Tables 1–4. The results are defined in Table 5.

The four scenarios have been computed in the Table I–4 and the following conclusions can be derived.

1. For a zero or low tax-paying corporate, the lease option will make more sense, since the lease pricing for 100% depreciable assets such as cogeneration plants is substantially lower than current market rates for loans. Leases are priced currently at IRRs of 10% p.a., as opposed to loan pricing of around 20–21% p.a. The difference

Table 3a

Loan option: tax-paying corporate

Quarters	Interest	Principal repayment	Depreciation	Tax saving	Cost of equity	Cash flows	Principal opening	Principal repayment	Principal outstanding	Cost of equity
1	—	0.0	—	—	—	1000.0	750 0	0 0	750.0	12 5
2	39.375	0 0	—	—	12 50	-34.9	750 0	0 0	750.0	12.5
3	39 375	0 0	—	—	12 50	-34.9	750 0	0.0	750.0	12.5
4	39.375	0.0	1000	430	12 50	395 1	750 0	0.0	750 0	12.5
5	39.375	0.0	—	—	12 50	-34.9	750 0	0.0	750.0	12 5
6	39.375	0 0	—	—	12 50	-34 9	750 0	0.0	750.0	12 5
7	39.375	0.0	—	—	12 50	-34 9	750 0	0.0	750.0	12.5
8	39.375	0 0	0	0	12 50	-34 9	750.0	0.0	750.0	12 5
9	39 375	0.0	—	—	12.50	-34 9	750.0	0.0	750 0	12.5
10	39.375	62.5	—	—	12 52	-97 4	750 0	62.5	687.5	12.5
11	36 094	62 5	—	—	12 50	-95.6	687 5	62.5	625.0	12 5
12	32.813	62 5	0	0	12.50	-93.7	625.0	62.5	562 5	12 5
13	29.532	62.5	—	—	12.50	-91 8	562.5	62.5	500 0	12.5
14	26 250	62 5	—	—	12 50	-90 0	500 0	62.5	437.5	12 5
15	22 969	62.5	—	—	12 50	-88.1	437 5	62 5	375.0	12 5
16	19 688	62 5	0	0	12 50	-86 2	375.0	62.5	312 5	12 5
17	16.407	62 5	—	—	12 50	-84.4	312.5	62 5	250 0	12 5
18	13.125	62 5	—	—	12 50	-82 5	250 0	62.5	187 5	12.5
19	9 844	62 5	—	—	12 50	-80.6	187 5	62 5	125.0	12.5
20	6.563	62 5	0	0	12 50	-78.7	125 0	62 5	62.5	12.5
21	3.282	62 5	—	—	12 50	-326 9	62.5	—	0.0	12 5

Note Initial capex 1000, equity 250, loan 750, depreciation rate 100%, capital expenditure Rs 1000, net present value @ 16% = Rs 775.72; interest on loan 21% per annum payable quarterly in arrears, term of loan five years, and repayment of loan in year 2–5 in equal quarterly instalments

Table 3b

Loan option· tax-paying corporate (repayment from quarter 1)

Quarters	Interest	Principal repayment	Depreciation	Tax saving	Cost of equity	Cash flows	Principal opening	Principal repayment	Principal outstanding	Cost of equity
1	—	0 0	—	—	12.5	1000 0	750.0	0 0	750.0	12 5
2	39.38	0.0	—	—	12 5	-34 9	750 0	37 5	712 5	12 5
3	37 41	37.5	—	—	12 5	-71.3	712 5	37 5	675.0	12.5
4	35 44	37 5	1000	430	12 5	359 8	675.0	37.5	637.5	12 5
5	33.47	37 5	—	—	12 5	-69 1	637 5	37 5	600.0	12 5
6	31.50	37 5	—	—	12 5	-68 0	600 0	37 5	562 5	12.5
7	29 53	37 5	—	—	12.5	-66.8	562.5	37 5	525 0	12 5
8	27 56	37.5	0	0	12 5	-65.7	525.0	37 5	487 5	12.5
9	25.59	37 5	—	—	12 5	-64 6	487.5	37 5	450.0	12 5
10	23.63	37 5	—	—	12 5	-63.5	450 0	37.5	412.5	12 5
11	21.66	37 5	—	—	12 5	-62 3	412.5	37 5	375.0	12 5
12	19.69	37.5	0	0	12 5	-61 2	375.0	37 5	337.5	12 5
13	17 72	37 5	—	—	12.5	-60 1	337 5	37 5	300 0	12 5
14	15 75	37 5	—	—	12 5	-59 0	300 0	37 5	262 5	12.5
15	13 78	37 5	—	—	12 5	-57.9	262 5	37 5	225.0	12 5
16	11.81	37 5	0	0	12 5	-56 7	225.0	37.5	187 5	12 5
17	9.84	37 5	—	—	12 5	-55 6	187 5	37.5	150.0	12 5
18	7 88	37 5	—	—	12 5	-54 5	150 0	37 5	112.5	12 5
19	5 91	37.5	—	—	12.5	-53.4	112 5	37 5	75 0	12.5
20	3 94	37 5	0	0	12 5	-52 2	75 0	37.5	37 5	12 5
21	1.97	37 5			12.5	-301 1	37 5	37 5	—	12 5

Note Initial capex 1000, equity 250, loan 750, depreciation *rate* 100%, capital expenditure Rs 1000, interest on loan 21% per annum payable quarterly in arrears, term of loan. five years, repayment of loan in year 2–5 in equal quarterly instalments, and net present value @ 16% = Rs 775 72

Table 4a

Loan option: zero tax corporate

Quarters	Interest	Principal repayment	Depreciation benefit lost	Cost of equity	Cash flows	Principal opening	Principal repayment	Principal outstanding	Cost of equity
1	—	0 0	—	—	1000	750 0	0 0	750 0	—
2	39.375	0 0	—	12 5	–51 9	750.0	0 0	750.0	12.5
3	39.375	0 0	—	12 5	–51 9	750.0	0 0	750 0	12.5
4	39.375	0 0	0	12 5	–51 9	750 0	0 0	750.0	12.5
5	39 375	0 0	—	12 5	–51 9	750.0	0.0	750.0	12.5
6	39.375	0 0	—	12.5	–51 9	750.0	0 0	750 0	12 5
7	39 375	0 0	—	12 5	–51.9	750.0	0 0	750 0	12.5
8	39 375	0 0	—	12 5	–51 9	750 0	0 0	750.0	12.5
9	39.375	0 0	—	12 5	–51 9	750.0	0 0	750·0	12.5
10	39.375	62 5	—	12.5	–114 4	750.0	62 5	687.5	12.5
11	36 094	62 5	—	12 5	–111 1	687 5	62 5	625.0	12 5
12	32 813	62 5	—	12 5	–107 8	625 0	62 5	562.5	12.5
13	29 532	62 5	—	12 5	–104.5	562 5	62.5	500 0	12 5
14	26 250	62 5	—	12 5	–101.3	500 0	62 5	437 5	12 5
15	22 969	62 5	—	12 5	–98 0	437 5	62 5	375.0	12 5
16	19 688	62 5	—	12 5	–94 7	375.0	62 5	312 5	12 5
17	16.407	62 5	—	12 5	–91 4	312 5	62 5	250 0	12 5
18	13 125	62 5	—	12.5	–88.1	250 0	62 5	187 5	12.5
19	9 844	62 5	—	12 5	–84 8	187 5	62 5	125 0	12.5
20	6 563	62 5	—	12 5	–81 6	125 0	62 5	62 5	12 5
21	3 282	62 5	—	12 5	–328 3	62 5	62 5	0 0	12 5

Note Initial capex 1000, equity 250, loan 750, depreciation rate 100%, capital expenditure Rs 1000· interest on loan 21% per annum payable quarterly in arrears, term of loan five years, repayment of loan in year 2–5, in equal quarterly instalments, net present value @ 16% = Rs 517 57

Table 4b

Loan option zero tax corporate (repayment from quarter 1)

Quarters	Interest	Principal repayment	Depreciation benefit lost	Cost of equity	Cash flows	Principal opening	Principal repayment	Principal outstanding	Cost of equity
1		0 0	—	—	1000 0	750.0	0.0	750 0	—
2	39.375	37 5	—	12 5	−89 4	750 0	37 5	712 5	12 5
3	37.407	37 5	—	12.5	−87 4	712.5	37 5	675 0	12 5
4	35.438	37.5	0	12.5	−85 4	675 0	37 5	637 5	12.5
5	33.469	37 5	—	12 5	−83 5	637 5	37 5	600 0	12 5
6	31 500	37 5	—	12 5	−81 5	600 0	37 5	562 5	12 5
7	29 532	37 5	—	12 5	−79.5	562 5	37 5	525 0	12 5
8	27 563	37 5	—	12.5	−77 6	525 0	37 5	487 5	12 5
9	25 594	37 5	—	12.5	−75 6	487 5	37.5	450 0	12 5
10	23 625	37 5	—	12.5	−73 6	450 0	37.5	412 5	12 5
11	21.657	37 5	—	12 5	−71 7	412 5	37.5	375 0	12.5
12	19.688	37.5	—	12 5	−69 7	375.0	37.5	337 5	12.5
13	17.719	37 5	—	12.5	−67 7	337 5	37 5	300 0	12.5
14	15.750	37 5	—	12.5	−65 8	300 0	37 5	262.5	12.5
15	13 782	37.5	—	12 5	−63 8	262.5	37 5	225 0	12.5
16	11 813	37 5	—	12 5	−61 8	225 0	37 5	187 5	12.5
17	9 844	37 5	—	12.5	−59 8	187 0	37 5	150 0	12 5
18	7 875	37.5	—	12.5	−57 9	150 0	37 5	112 5	12.5
19	5.907	37 5	—	12 5	−55 9	112 5	37 5	75.0	12.5
20	3.938	37.5	—	12.5	−53 9	75 0	37 5	37 5	12 5
21	1 969	37.5	—	12 5	−302 0	37 5	37 5	0 0	12 5

Note Initial capex 1000; equity 250, loan 750, depreciation rate 100%, capital expenditure Rs 1000, interest on loan 21% per annum payable quarterly in arrears, term of loan five years, repayment of loan in year 2–5, in equal quarterly instalments, net present value @ 16% = Rs 446 18

Table 5

NPVs under different scenarios for 100% depreciable assets (calculations in Tables 1–4)

Mode	Zero tax corporate (Rs)	Tax-paying corporate (Rs)
Lease	539	473
Loan	517	834
	(446)	(775)

Note Figures in brackets indicate the NPV of a transaction if the principal repayment were to start from Quarter 1 instead of Quarter 9 in equal instalments during the loan tenor

in NPVs between a lease and a loan option will also depend on the terms of the repayment of the loan. For example, we have assumed in Table 1 that the loan repayment starts only after Quarter 8 If the loan repayment were to start from Quarter 1, the NPV of the loan option would fall to Rs 474.

2 For a high tax-paying corporate, the loan option would make substantially more sense as is reflected by the comparative NPVs in the table above. The difference is substantial, since a tax-paying corporate derives much more benefit from taking an up-front tax benefit rather than take a lease which is priced lower. The difference in NPVs is huge because cogen plants attract 100% depreciation and the up-front tax benefit cannot be outweighed by a cheaper lease option. If one were to experiment on a similar basis with an asset attracting 25% depreciation, the results would get altered to some extent (Table 6).

For zero tax corporates, a loan would be more beneficial than a lease for 25% depreciation assets at current market rates. This is because a lease for 25% depreciable assets are often priced very similar to loans. The depreciation benefit for lessors or owners is not as substantial as what is offered by 100% depreciable assets. That is the reason why the NPV of a loan for a tax-paying corporate has come down to Rs 701 from Rs 839 (in case of 100% depreciable assets). Thus, though the loan still makes sense for tax-paying corporates, the difference in the benefits of the two options comes down.

Table 6

NPVs for different scenarios for 25% depreciable assets (calculations in Tables 7–10)

Mode	Zero tax corporate (Rs)	Tax-paying corporate (Rs)
Lease finance for 25% depreciation assets	462	548
Loan	517	696
	(446)	—

Table 7

Financial lease option: tax-paying corporate

Quarters	Lease rent	Post-tax lease rent	Depreciation	Depreciation benefit lost	Post-tax cashflow
1	1000	—	—	—	—
2	-78	-44 46	—	—	-44.46
3	-78	-44 46	—	—	-44.46
4	-78	-44 46	—	—	-44 46
5	-78	-44 46	250 00	107 50	-151 96
6	-78	-44 46	—	—	-44 46
7	-78	-44 46	—	—	-44 46
8	-78	-44 46	—	—	-44 46
9	-78	-44 46	187 50	80 63	-125 09
10	-78	-44 46	—	—	-44 46
11	-78	-44 46	—	—	-44 46
12	-78	-44 46	—	—	-44.46
13	-78	-44 46	140 63	60 47	-104 93
14	-78	-44 46	—	—	-44 46
15	-78	-44.46	—	—	-44 46
16	-78	-44 46	—	—	-44 46
17	-78	-44 46	105 47	45 35	-89 82
18	-78	-44 46	—	—	-44.46
19	-78	-44.46	—	—	-44 46
20	-78	-44 46	—	—	-44 46
21	-78	-44 46	79 10	34 01	-88.47

Note Initial capex 1000, depreciation rate 25%, capital expenditure Rs 1000, lease rental Rs 78 per 1000 of capex. per month, residual value one per cent of capex, net present value @ 16% = Rs 548.08

The conclusion we derived from Table 5 for 100% depreciable assets in case of zero tax corporates gets reversed. As explained earlier, the difference between NPVs in case of zero tax corporates for a lease and a loan option is substantial because of the enormous difference in the current market rates for loans (at 21%) and leases (at 10–11%). Since this difference does not exist or is marginal in the case of 25% depreciable assets, the loan NPV at Rs 517 is higher than the lease NPV at Rs 462. The loan NPV is higher at Rs 474 in this scenario even if the loan repayment is started at Quarter 1 instead of at the end of Quarter 9.

This leads us to a few more conclusions about issues which have to be examined before making a choice between lease or loan financing options.

1 The depreciation rate of the asset to be leased is a critical variable while arriving at a decision.
2. The terms of the loan, such as the repayment schedule and the interest rate, will have a bearing on the decision. Typically, the lease repayment will start almost immediately from the first month or quarter, in equal instalments through the period of the lease. However, loan repayments are more atypical, and may or may not have a moratorium on repayment of principal.

Table 8

Financial lease option: zero tax corporate

Quarters	Lease rent	Post-tax lease rent	Cash flows
1	—	—	1000
2	–78	–78	–78
3	–78	–78	–78
4	–78	–78	–78
5	–78	–78	–78
6	–78	–78	–78
7	–78	–78	–78
8	–78	–78	–78
9	–78	–78	–78
10	–78	–78	–78
11	–78	–78	–78
12	–78	–78	–78
13	–78	–78	–78
14	–78	–78	–78
15	–78	–78	–78
16	–78	–78	–78
17	–78	–78	–78
18	–78	–78	–78
19	–78	–78	–78
20	–78	–78	–78
21	–78	–78	–88

Note Initial Capex: 1000; depreciation rate. 25%, capital expenditure: Rs 1000; lease rental Rs 78 per 1000 of capex per month; residual value one per cent of capex; net present value @ 16% = Rs 462 96

Increasingly, lessors have tended to structure lease rents to suit the lessee's cashflows. Lessors can structure an increasing, decreasing, or variable rental flow with time to suit the lessee's requirements. This makes the lease versus loan evaluation more complex. A lessor can even try and match a loan repayment schedule which offers a moratorium on principal repayment for a number of years by keeping the initial lease rentals equal to the interest on the loan for the initial few years.

Other critical parameters affecting the choice are listed below.

1. Current corporate taxation rates.
2. Lessee's debt/equity ratio and ability to contract more debt. Current accounting practice in India allows leases to be footnoted in the balance sheet of the lessee, and hence to that extent a lease is a source of 'off-balance sheet' financing. It does not affect the debt/equity ratio as the obligations under the lease are not capitalized in the balance sheet of the lessee. This 'off-balance sheet' nature of lease financing is often a motivation for corporates to use the lease as a means of asset creation.

Table 9

Loan option tax-paying corporate

Quarters	Interest	Principal repayment	Depreciation	Tax saving	Cost of equity	Cash flows	Principal opening	Principal repayment	Principal outstanding	Cost of equity
1	—	0 0	—	—	—	1000 0	750.0	0.0	750 0	—
2	39 38	0 0	—	—	12 5	-34 9	750 0	0 0	750 0	12 5
3	39 38	0 0	—	—	12 5	-34 9	750 0	0 0	750 0	12 5
4	·39 38	0 0	250 00	107 50	12 5	72 6	750 0	0 0	750 0	12.5
5	39 38	0.0	—	—	12 5	-34 9	750 0	0.0	750 0	12 5
6	39 38	0 0	—	—	12 5	-34 9	750 0	0 0	750 0	12 5
7	39 38	0 0	—	—	12 5	-34 9	750 0	0 0	750 0	12 5
8	39 38	0 0	187 50	80 63	12 5	45 7	750.0	0.0	750 0	12 5
9	39 38	0 0	—	—	12 5	-34.9	750 0	0 0	750 0	12 5
10	39 38	62 5	—	—	12 5	-97 4	750 0	62 5	687.5	12 5
11	36 09	62 5	—	—	12.5	-95 6	687 5	62 5	625 0	12 5
12	32 81	62 5	140 63	60.47	12 5	-33 2	625 0	62 5	562 5	12 5
13	29 53	62 5	—	—	12 5	-91 8	562 5	62 5	500 0	12 5
14	26 25	62 5	—	—	12 5	-90 0	500 0	62 5	437 5	12 5
15	22 97	62 5	—	—	12 5	-88.1	437 5	62 5	375.0	12 5
16	19 69	62 5	105 47	45.35	12 5	-40 9	375 0	62 5	312 5	12.5
17	16 41	62 5	—	—	12 5	-84 4	312 5	62 5	250 0	12 5
18	13.13	62 5	—	—	12 5	-82 5	250 0	62.5	187 5	12 5
19	9 84	62 5	—	—	12 5	-80 6	187 5	62 5	125 0	12.5
20	6 56	62 5	79 10	34 01	12 5	-44 7	125 0	62 5	62 5	12.5
21	3 28	62 5	—	—	12·5	-326 9	62 5	62 5	0 0	12.5

Note Initial capex 1000, equity 250, loan 750, depreciation rate = 100%, capital expenditure Rs 1000, interest on loan = 21% per annum payable quarterly in arrears, term of loan five years, repayment of loan in year 2–5, in equal quarterly instalments, net present value @ 16% = Rs 696 86

Table 10a

Loan option: zero tax corporate

Quarters	Interest	Principal repayment	Depreciation benefit lost	Cost of equity	Cash flows	Principal opening	Principal repayment	Principal outstanding	Cost of equity
1	—	0 0	—	—	1000 0	750.0	0.0	750.0	—
2	39 375	0.0	—	12.5	–51.9	750.0	0 0	750 0	12 5
3	39 375	0 0	—	12 5	–51 9	750.0	0.0	750 0	12.5
4	39.375	0.0	0	12.5	–51 9	750 0	0 0	750.0	12.5
5	39.375	0.0	—	12.5	–51 9	750 0	0 0	750.0	12.5
6	39.375	0 0	—	12 5	–51 9	750.0	0.0	750 0	12.5
7	39 375	0.0	—	12.5	–51 9	750 0	0 0	750 0	12.5
8	39 375	0 0	—	12.5	–51 9	750.0	0.0	750.0	12 5
9	39 375	0.0	—	-12.5	–51.9	750 0	0.0	750.0	12.5
10	39.375	62.5	—	12.5	–114 4	750.0	62.5	687 5	12.5
11	36 094	62.5	—	12.5	–111 1	687.5	62 5	625.0	12.5
12	32.813	62 5	—	12 5	–107 8	625.0	62.5	562.5	12.5
13	29.532	62.5	—	12.5	–104 5	562 5	62.5	500 0	12.5
14	26 250	62 5	—	12 5	–101 3	500 0	62 5	437 5	12.5
15	22 969	62 5	—	12 5	–98 0	437.5	62 5	375.0	12 5
16	19 688	62.5	—	12 5	–94 7	375 0	62 5	312 5	12.5
17	16.407	62 5	—	12.5	–91 4	312 5	62 5	250 0	12 5
18	13 125	62.5	—	12.5	–88 1	250 0	62.5	187 5	12.5
19	'9 844	62.5	—	12 5	–84 8	187 5	62.5	125 0	12 5
20	6 563	62 5	—	12 5	–81 6	125 0	62 5	62 5	12 5
21	3 282	62 5	—	12 5	–328 3	62 5	62 5	0 0	12 5

Note Initial capex 1000, equity 250, loan 750, depreciation rate 25%, capital expenditure Rs 1000, interest on loan = 21% per annum payable quarterly in arrears, term of loan = five years, repayment of loan in year 2–5, in equal quarterly instalments, net present value @ 16% = Rs 517 57

Table 10b

Loan option: zero tax corporate (repayment starting from quarter 1)

Quarters	Interest	Principal repayment	Depreciation benefit lost	Cost of equity	Cash flows	Principal opening	Principal repayment	Principal outstanding	Cost of equity
1	—	0.0	—	—	1000 0	750 0	0.0	750 0	—
2	39 375	37 5	—	12.5	−89 4	750.0	37.5	712 5	12 5
3	37.407	37.5	—	12 5	−87 4	712 5	37 5	675.0	12 5
4	35.438	37 5	0	12 5	−85 4	675 0	37 5	637 5	12.5
5	33.469	37 5	—	12 5	−83 5	637 5	37 5	600 0	12.5
6	31 500	37 5	—	12.5	−81 5	600 0	37 5	562 5	12 5
7	29.532	37 5	—	12 5	−79.5	562 5	37 5	525 0	12 5
8	27 563	37 5	—	12 5	−77 6	525.0	37 5	487 5	12 5
9	25 594	37 5	—	12.5	−75 6	487 5	37 5	450 0	12.5
10	23 625	37 5	—	12.5	−73 6	450 0	37 5	412 5	12 5
11	21 657	37 5	—	12 5	−71 7	412 5	37 5	375.0	12.5
12	19 688	37 5	—	12.5	−69 7	375 0	37.5	337 5	12.5
13	17.719	37 5	—	12 5	−67 7	337 5	37 5	300.0	12 5
14	15 750	37 5	—	12 5	−65 8	300 0	37 5	262 5	12 5
15	13 782	37 5	—	12.5	−63 8	262 5	37 5	225.0	12 5
16	11 813	37 5	—	12 5	−61 8	225 0	37 5	187 5	12 5
17	9 844	37 5	—	12 5	−59 8	187 5	37 5	150 0	12 5
18	7 875	37 5	—	12 5	−57 9	150 0	37 5	112 5	12 5
19	5 907	37 5	—	12 5	−55 9	112.5	37 5	75 0	12 5
20	3.938	37 5	—	12 5	−53.9	75 0	37 5	37 5	12 5
21	1 969	37 5		12 5	−302 0	37 5	37 5	0 0	12.5

Note Initial capex 1000, equity 250, loan 750; depreciation rate. 25%, capital expenditure Rs 1000, interest on loan 21% per annum payable quarterly in arrears, term of loan five years, repayment of loan in year 2–5, in equal quarterly instalments, net present value @ 16% = Rs 446 18

However, in a number of countries, accounting standards require financial leases to be capitalized in the balance sheet. The present value of all financial leases has to be shown alongside the outstanding debt in the balance sheet.
3. Restrictive covenants in loan or lease agreements.

Changes Introduced by the 1996/97 Budget

There have been recent changes introduced by the 1996/97 budget, which will affect the financing choices available to developers of cogen plants, especially those considering leasing as a means of financing for their plants. The budget allows lessors to share depreciation to the extent of their investment in the leased asset.

Typically, a large project or plant costing, say, Rs 1000 million found few interested lessors. The reason for this was essentially that very few lessors had a tax appetite for such a large asset, which would give a one-time tax benefit of such a large amount. Also, lessors prefer to spread their risks over a number of leases rather than take one large exposure on a single lessee. Since the cogen plant was one single unit eligible for 100% depreciation (the individual components were not eligible for 100% depreciation), it was rare to find a large lessor who would be interested in leasing the plant.

The recent change which has been introduced makes it possible for a number of lessors to get together and lease the entire cogen facility as a consortium to a lessee. We see this as a measure which will introduce and encourage project leasing in India. Most financial leasing in India has so far been of capital equipment which is part of large projects rather than of entire projects. Now, one will see structured lease deals which will be much more complex and of larger magnitudes.

Since leasing is tax-driven, a number of measures which affect corporate income tax calculations will have a bearing on rates for financial leasing. Some of these are listed below.

1. The recent budget puts an end to the infamous sale and leaseback deals by stating that the lessor in case of a sale and leaseback transaction will be able to capitalize the purchased asset only at a value equal to the 'written down value' in the lessee's books and not at the revalued price. Prior to this change, a number of corporates 'refinanced' their cogeneration plants using this route.
2. The introduction of the 'minimum alternative tax' for companies will affect leasing companies and lessors to the extent that they will now have to pay a minimum tax on 30% of their book profits. However, they are expected to plan their tax shelter requirements in such a manner so as to pay only the minimum tax and no more. Lease rates are not likely to change.
3. The corporate tax rate has come down from 46 to 43%. Lease rentals for financial leases are expected to be revised upwards marginally as the up-front tax benefit gets reduced marginally.

Contractual Issues Concerning Cogeneration

Dan Jantzen[1]

Introduction

While discussing contractual issues concerning cogeneration, it is important to initially distinguish between two ownership patterns for a cogeneration plant (Figure 1). In the case where the ownership of the host facility and the ownership of the power plant is with a single company, i.e., a single entity, then, obviously, in terms of contractual issues, it is the simpler of the two options. The other case is where the ownership of the host processing facility and the power plant differs. There are a number of ways this could be arranged. It could be that the power plant enters into a joint venture agreement between the host facility and an outside developer who is hoping to develop the cogen project. It could be that the outside developer is the sole owner of the power plant or there could be situations in which either of the state electricity boards (SEBs), or the person who is buying the power, or even some of the financing agencies, might share the ownership of the power plant. From a contractual point of view, the second case is clearly more complex.

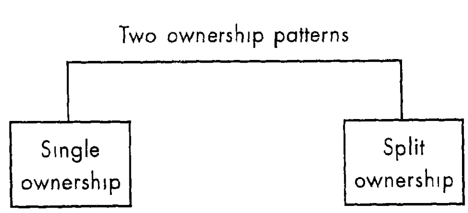


Figure 1. *Two ownership patterns*

[1] Renewable Energy Project Support Office, Winrock International, 7, Poorvi Marg, Vasant Vihar, New Delhi - 110 057, India.

Single Ownership

In the case of the single ownership of the processing plant and the power plant (Box 1 and Figure 2a), there exists, clearly, a power purchase agreement (PPA) to deal with the sale of the export of power from the plant. One may need a fuel supply agreement (FSA) to deal with any additional fuel which will be purchased to operate the power plant. And, of course, there is a financing agreement (FA) to finance the construction of another power plant. These are the three main contracts that one needs to put in place.

Split Ownership

When there is a split ownership of the host facility and the power plant (Box 2 and Figure 2b), one still needs to sign the PPA; one may still need the FSA; and one may still need the same FA. However, in addition, there needs to be an agreement over who is going to operate the facility – whether it is going to be the person who owns the power plant, or, whether someone from the processing plant will operate this facility. This needs to be worked out and agreed to.

Other Options

There may also be a case in which the power plant would be built on the premises of the processing plant. In that case, some sort of a land purchase or land use agreement

Box 1
Single ownership

- PPA
- FSA
- FA

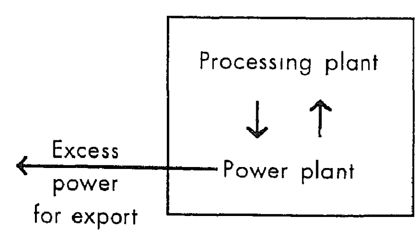


Figure 2a. *Single ownership*

Box 2
Split ownership

- PPA
- FSA
- FA
- Operation agreement
- Land purchase lease agreement
- Fuel steam power exchange agreement

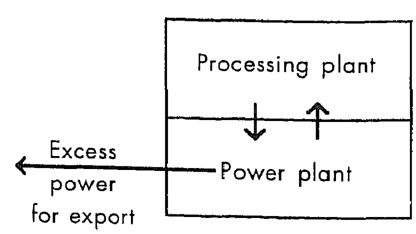


Figure 2b. *Split ownership*

would need to be put in place for the land that would be occupied by the power plant. The other agreement that is clearly needed here is one that deals with the exchange of fuels – steam and power – between the two facilities. This agreement could either be placed on a broader basis, in which it is agreed that a certain amount of power is exchanged for steam and fuel, or for each of these commodities, on a cash basis; and a cash record kept of how much of each of these commodities is moving back and forth. The transaction can then be calculated and worked out, as to how much money is owed by either party to the other.

Contractual Issues

The paper now focuses on the PPAs and the principles involved in cogeneration. The PPA is perhaps the most difficult contract to arrange, and one needs to be more concerned about it. The purpose of the PPA is to define the obligations of each party to the agreement and to spell out what can happen, under any circumstances, which could arise, in future, in the operations of this plant (Box 3). Perhaps, the most important part of the PPA is that it needs to be financeable, in the sense that the agencies, who will be lending money for the construction of the plant, would like to ensure that the cash flow arising from the sale of power would be adequate to cover the payments for the loan that is to be taken. The question of financeability, of course, needs to be struck with the financing agency itself, who would testify what would be satisfactory and acceptable to them.

Some of the items to be covered under a PPA can be listed here (Box 4). No PPA has to be the same, i.e., there is a wide range of variation in the terms of the PPAs. But, in general, the items listed in Box 4 need to be covered and specified by the parties to the contract. The link of the contract has to be specified, only then the terms of the contract will be effective. There is, then, a whole section on the terms for the power sale. This includes a whole lot of items – the tariff rate; whether or not the tariff would vary by peak or off-peak power sale; etc. There might be some variation in terms of the time of year. It is a possibility that the tariff would be based on a capacity payment or an energy payment, or that it might be lumped together in a single energy rate. Some escalation due to inflation needs to be built into the contract. And, there needs to be a clearly classified procedure for how any escalation would be calculated.

In terms of inter-connection arrangements, it is essential that one needs to spell out clearly as to who is paying for which of the inter-connection equipment, who owns it, and who is maintaining it. In terms of continuity of service, it is important to specify

Box 3
PPA – Principles

- Define the obligations of each party
- Spell out 'what happens' under any circumstances which could arise

Box 4

PPA – Items to be covered

- Parties to the contract
- Term of the contract
- Terms and tariffs for power sale
- Interconnection arrangements
- Continuity of service
- Safety provisions
- Metering
- Permits and licenses
- Default and termination
- Indemnification
- *Force majeure*
- Authority to execute
- Liability
- Conflicts
- Definitions

what happens when the generator is unable to provide the power that has been contracted for, and vice versa. What happens when the buyer is unable to evacuate the power, either because of the great disturbances or because of other problems? For example, metering is important. We would, therefore, need to specify where the metering is to be done, and who is going to do it. How often are the readings to be taken? How the metre readings to be calculated? These and other similar issues need to be looked at and specified.

Conclusion

It is important to accept and realize that these contracts do not have to be all identical. One is not sure whether one can have a single draft answer that applies to everyone. Cogeneration is quite a varied subject, and a contract will have to be adjusted and revised to suit the conditions of the particular situation. If one looks at some of the contracts that have been proposed in India, one finds that they tend to be rather brief. Perhaps there is not much experience available in handling such contracts. In countries where this has been going on for some time, one can find that the contract becomes much more extensive. And, essentially, what is happening here is that as experience is gained, one is able to identify additional topics and clauses which needs to be included. The International Cane Energy Network has published a compendium of 12 civil cogeneration power sale contracts which are in force and are being applied firmly. This document is available with Winrock International, for US $500, and could provide more insight into the subject discussed in this paper.

Independent Project Developer Views on Contractual Issues Concerning Cogeneration: Specific Reference to India

Anand S Dayal[1]

Introduction

Chatborne and Park (C&P) is an international law firm based in New York. It has been an active participant worldwide in the development of international power projects, including cogeneration projects. In India, C&P represents approximately 25 power projects being developed throughout the country.

Our firm is also currently advising developers on two of the seven fast-track projects that are eligible for counterguarantees. All these projects are those that were developed in India after the 1991 opening up of the power sector by the Government of India. C&P's role in the development of these projects has to been to handle all aspects of project documentation including the negotiations and drafting of documents.

Landmark Documents

Some of the landmark documents that have been negotiated by C&P and drafted on behalf of the developers in India are outlined below. C&P has drafted and successfully negotiated the first power purchase agreement (PPA) that was executed in India since the opening up of the power sector. It also negotiated the first long-term project – financeable fuel supply agreement with the subsidiary of Coal India, and has also completed three engineering procurement construction (EPC) contracts and several operation and maintenance (O & M) agreements for projects in India. C&P is also in the process of preparing financing documents for the financial closure of some projects in India.

[1] Chatborne and Park Associates, A-16B, Anand Niketan, New Delhi, India.

With respect to cogeneration specifically, the lawyers at C&P have been involved in drafting the regulations that were promulgated in the US for cogeneration projects pursuant to the Public Utility Regulatory Policies Act (PURPA). PURPA was enacted in part to require the purchase of power by public utility companies from a qualified facility, i.e., a facility which included cogeneration plants that met certain requirements. In addition to preparing these regulations, the lawyers at our firm also defended these regulations against the constitutionality challenges in a landmark US Supreme Court decision called Park versus the State of Mississippi. These regulations as they turned out, although probably not perceived at the time that they were framed, have established the independent power framework upon which the independent power industry in the US has been established. And, to a large extent, there are striking parallels between the framework they have established for serving PURPA in the US, and the framework, as it is evolving, that is established in India.

PPAs

This paper deals with certain aspects related to PPAs. Instead of outlining the contractual clauses themselves, the paper briefly discusses certain issues related to the dynamics involved in negotiating and finalizing these PPAs.

The PPA is a document on which the financial viability of a project depends. This is because the PPA establishes the revenue stream that a project requires to meet its financial commitment to the parties providing the capital that it required. Of course, in the case of a cogeneration project, there would also most likely be a steam sale agreement, which would represent an additional source of revenue for the project. However, the issues faced by non-cogeneration independent power producers in negotiating PPAs would also be faced by developers of cogen projects. Although most cogen projects are smaller, and there is a single captive customer for the sale of power, there are large cogeneration projects which sell at least a portion of the power that they generate to the state electricity board (SEB). The terms and conditions of the sale of this power would be a crucial aspect of their financeability and economic viability. In this respect, therefore, a cogeneration project is very similar to a regular independent power project making sales directly to the SEB.

Uncertainty

The two specific areas related to the dynamics of negotiating PPAs are as follows. First is the uncertainty regarding the degree to which the central government, either the Central Electricity Authority (CEA), the Ministry of Power (MoP), or the Ministry of Finance (MoF) will be involved in the process of the development of the project, in particular the negotiation of the PPA. At present, it is not clear to what extent PPAs negotiated by the developer at the state level would be subject to additional scrutiny at the central government level. Secondly, based upon C&P's experiences in India, I would like to focus upon the implications that such an involvement on the part of the central government may have upon project agreements that have already been negotiated at the state level. One key implication of this sort of opening up of PPAs is the resulting uncertainty. For example, it is not clear whether the Centre's scrutiny will be limited to the specific issues upon

which the central government has a direct interest or a more general one, or whether the central government will conduct a more general review encompassing all aspects of the PPA. Although, I, personally, have no disagreement with the need for central government involvement in power projects that have been negotiated at the state level, what is of concern is the uncertainty created in the process of developing a project to the extent of the actual changes required by the Centre, which involve significant development risks.

In this regard, I believe that it is not inappropriate to sound a note of caution to developers that, under the present circumstances, if they choose to ignore matters that may later be raised by the CEA, the MoP, or the MoF, they run the risk of progressing far along the development of the project at the state level, only to watch their efforts being swept away later by a far-reaching change in the fundamentals of the project required by this review at the Centre. It is not inconceivable, and we have seen this happen. A project that was carefully negotiated and structured at the state level, and was found to be financeable by the lenders as well, may, as a result of the subsequent review at the central level, be rendered non-financeable. The question of the level of scrutiny of the PPA at the central level would depend primarily on the central government's perception of the need for it to be involved in conducting such a review.

Risks

Therefore, essentially, there is a big unknown factor involved in developing power projects. Increasing awareness among developers that cutting a deal at the state level and negotiating a PPA is not enough. They will have to keep in mind and anticipate what might be required for the project documentation by the central government, as it has very strong interests in ensuring the uniformity of the development of the energy sector throughout the country. The central government is not shy about asserting itself. And, if it does so after a developer has signed the document at the state level, large-scale changes to the documents and to the fundamentals of the project may be required even at that stage.

Cogeneration in Sugar Mills: Some Technical and Commercial Issues

Harish Bhargava[1]

Introduction

Generation of exportable electricity from bagasse in sugar mills is universally accepted as desirable, economic, and environment friendly; and, the potential of this electricity source is substantial. Cogeneration projects can be implemented in a short time, and at reasonable costs. And, since sugar mills are located in rural areas, cogenerated electricity will aid the development of neighbouring villages as well. Despite such significant advantages, projects for cogeneration of exportable electricity in sugar mills are not coming up as they should.

For catalysing such projects, it is essential that the sugar mills, the state electricity boards (SEBs), financial and developmental institutions, and the concerned ministries in the central and the state governments work together in close coordination to address the technical and commercial issues that are critical to the development and long-term functioning of the projects.

However, the sugar mills have to take the first step and address these issues. Committed technical and commercial long-term support from the SEBs is the next step. The role of the central and the state governments is to help the sugar mills and the SEBs arrive at fair and mutually beneficial arrangements, provide reasonable financial support, and frame stable and long-term policies taking the critical issues into consideration.

Technical Issues

The most important technical issues that need to be addressed are listed below:

1. Improving technical and operating efficiencies:
   - in cane preparation;
   - in milling;

[1] MITCON Ltd, P B No. 923, Kubera Chambers, Shivajinagar, Pune - 411 005, India.

- in the manufacturing process;
- of energy systems; and
- of maintenance.

2. Installing energy-efficient equipment in:

   - steam generation;
   - electricity generation;
   - mill drives;
   - the process, e.g., evaporators, heaters, and crystallizers; and
   - centrifugal drives.

3. Optimum design and configuration of the energy system for processing and power generation.
4. Energy conservation.
5. Evacuation of surplus power.

Cogeneration levels in sugar mills can be substantially increased by the introduction of latest technologies based on energy-efficient equipment and systems for manufacturing sugar, high-pressure boilers for raising steam, high-efficiency turbines for generating power, and implementing energy conservation and economy measures to reduce consumption of steam and electricity in sugar mills. This can result in a significant surplus of electric energy from sugar mills in a relatively short time and at economical costs.

Although issues related to the production of sugar are well known to the sugar mills, the importance of optimizing these for efficient cogeneration of electricity needs to be fully appreciated and recognized. The energy system design, however, merits a close look.

Energy System Design and Optimization

It is necessary that the cogeneration system is carefully designed to take full advantage of the potential in each individual sugar mill and, at the same time, meet the energy demand pattern of the region in which the sugar mill is operating. Such optimization can be achieved through a detailed analysis, to be followed by the integration of sugar mill operations, electric load demand pattern of the region, and the future requirements.

High-efficiency Boilers and Turbines

Boilers and turbines operating at high pressures/temperatures and with high efficiencies are now available in India. They need to be carefully selected on the basis of a long-term benefit/cost analysis.

Potential cogenerators are apprehensive about operating such 'hi-tech' power plants. These are totally unfounded and have to be removed by upgrading the knowledge base of the potential investors. With the correct choice of power plant components and the proper training of the operators, such fears are unfounded. Keeping the techno-economic considerations relevant to India in mind, it would be desirable to standardize the boiler pressure at 63 bars, and the temperature at 480 °C.

Water treatment is also an important aspect. The make-up boiler feedwater should be of satisfactory quality and must be condensate-free. Proper water treatment is essential even if the boilers are operating at lower pressures of 21, 32, or 42 bars.

The choice of turbines, of course, will depend on the boiler pressure. Depending on the mode of operation, the turbine could be a simple back-pressure type or a controlled extraction and/or bleed or condensing type, or a combination of these.

The Four Modes for Cogeneration

Maximizing the cogeneration of electricity in sugar mills can be based on one of the four modes depicted in Boxes 1–4. The choice is governed by the inputs available on the one hand and the pattern of additional power requirements on the other. It is important to recognize that irrespective of the choice of the cogeneration mode, the use of high-pressure boilers and high-efficiency turbines, and the realization of maximum energy economy are the absolute imperatives for maximizing net exportable power from any sugar mill.

Box 1

*Mode 1**

- Fuel: only bagasse.
- Duration: only the crushing season.
- Steam/power generation: to meet process requirements.
- Bagasse usage: surplus bagasse to be disposed.
- Support fuel: none.
- Type of turbine: back-pressure.

* This mode is used in all the Indian sugar mills.

Generating capacity and the quantum of electricity produced can be maximized only by operating at the highest economic steam pressure and the temperature considered operationally feasible, such as 63 bars, 480 °C, by reconfiguring the process requirements to achieve maximum economy in the consumption of steam and power, and by adopting energy conservation measures. Maximization of power generation can be achieved through minimum additional investment, which will also lower the cost of producing sugar. The energy produced will vary from time to time, with the changes in the rate of cane crushed and the corresponding production of bagasse.

Faced with power shortages, especially if the peak period of the grid coincides with the crushing season, the SEB may prefer that the sugar mill maximize power generation during the crushing season by utilizing all the bagasse as it is produced. The energy thus produced may either be sold to the SEB, wheeled to other units during the crushing season, or banked with the SEB for use within and/or outside the crushing season. Mode 2 provides for such a requirement.

Box 2

Mode 2

- Fuel: only bagasse.
- Duration: only the crushing season.
- Steam/power generation: maximum (utilizing all available bagasse).
- Bagasse usage: bagasse as produced, fully consumed.
- Support fuel: none.
- Type of turbine: extraction/condensing.

The use of an extraction/condensing turbine is essential, with the steam in excess of the process requirements going through the condenser. The sizing of the condensing part of the turbine will need to be such as to handle maximum steam flow after meeting the minimum process steam requirements. The level of energy production can also be better stabilized under this mode, if some bagasse is stored in an intermediate storage facility, and is subsequently used during periods of low crushing rate.

Mode 3 is relevant in a situation where the region where the sugar mill is located has its peak demand period after the crushing season, say during June–November. This mode can also be used if the SEB requires a uniform power supply from the sugar mill over a long period, say 270 days in a year. The rate of consumption of bagasse during the crushing season and of the stored bagasse during the off-season will also have to be regulated such that the desired level of power export can be maintained.

The size of the condensing part of the turbine should be based on the maximum rate at which power will be required to be generated during the off-season.

Mode 4 would be the ideal choice for mills located in regions where secondary fuel is available at economic costs, with a short transportation lead and high reliability of supply. The advantages of this mode include:

Box 3

Mode 3

- Fuel: only bagasse.
- Duration: the crushing season, and for a limited period beyond the crushing season.
- Steam/power generation: to meet the process requirements during the crushing season, and as required and feasible, beyond the crushing season.
- Bagasse usage: surplus bagasse to be stored and used after the crushing season.
- Support fuel: none.
- Type of turbine: extraction/condensing.

Box 4
Mode 4

- Fuel: primary – bagasse; secondary – agro-waste/coal/lignite/low sulphur heavy stock (LSHS)/furnace oil or natural gas (as economically available).
- Duration: round the year.
- Steam/power generation: maximum, more than what is required to meet process requirements.
- Bagasse usage: all bagasse to be used; no surplus.
- Support fuel: agro-waste/coal/lignite/LSHS/furnace oil or natural gas (as economically available).
- Type of turbine: extraction/condensing.

- power generation and export at a high and steady level;
- feasibility of operating the system at the maximum economic rating;
- availability of energy to the SEB throughout the year; and
- the productive use of capital invested, without any idling.

The capital cost of the system will be relatively high, as additional facilities for handling the support fuel, ash disposal, and air pollution control will be necessary. As against this, the energy generated will be much more – reliable supply available throughout the year – resulting in higher revenue. Since the capital invested will not be idle during the off-season, the incidence of the fixed cost component on the cost of generation will be lower. The economic viability of this mode must, therefore, be very carefully assessed.

Alternative Configurations

A number of alternative configurations of the boiler/turbine/alternator system are possible. A few of these are listed below.

- Replacement of the entire system.
- A new high-pressure boiler and topping turbine linked to existing system.
- Back pressure, controlled extraction, and condensing turbines.
- Bleed for providing steam to sulphur burners and centrifugals.
- High voltage alternator.

The objective of optimizing power generation and cost can, therefore, be realized through a judicious choice.

Energy Economy

The internal consumption of energy, including that of the generated electricity, must be minimized. This requires use of energy-efficient equipment, energy conservation measures, and elimination of wastage.

Integration between the Generating Plant and the Grid

It is essential that the design and equipment specifications of the generating and interconnecting equipment must be such as to make interconnected operation with the grid totally trouble-free. The generated power must meet the internal requirements and the needs of the SEB as optimally as possible. This calls for the provision of the required operational flexibility at the design stage, followed by efficient and well-coordinated operational management.

Commercial Issues

The basic commercial issues that have to be considered here are listed below.

- Evacuation and power supply contracts based on remunerative long-term prices, and prompt and assured payment for the exported power.
- Capital investment and one-time incentives.

Evacuation and Power Supply Contracts

Direct Radial Supply to End Users

Supply by the sugar mill to own or related units at the same location is ideal. It may also be possible to supply other units in the immediate neighbourhood through independent and dedicated tie-lines. Small producers of power should be allowed the 'right of way' over public roads, etc., with minimum formalities and at nominal charges.

Any legal hurdles blocking such arrangements need to be removed through amending the concerned legislation. However, in most cases, it may not be possible to evacuate all exportable power through this mode.

Sale/Purchase: Cogenerators vis-à-vis SEB

This arrangement is the most desirable since it ensures the equitable and economic utilization of exportable power. Long-term supply contracts entered into must be such that the interests of both the cogenertors and the SEB are adequately served and protected. It should be possible for the stipulated operational requirements to be met by both sides, without leading to unacceptable problems. The price must provide the producer a reasonable return throughout the expected life of the investment. At the same time, the price should be such that the SEB can afford to pay it. Further, the contracts should not only cover the current issues, but also provide for permanent and long-term safeguards for both parties.

Wheeling

This implies that the real time' supply of power from the producer to the end user by wheeling of energy through the SEB grid. The energy supplies is withdrawn by the end user at the same time or within a short interval, and the SEB is paid a wheeling charge for use of the transmission facilities. Under this the supply could either be:

- to one's own units at the same or different location/s; or
- to other units at the same or different location/s.

Wheeling charges should be reasonably low, not more than seven per cent of the energy supplied and should be recovered in the form of the energy retained. The price should be as mutually negotiated between the producer and the end user based on the prevalent market conditions.

Banking

This arrangement is similar to wheeling, except that it is not 'real time' Energy supplied to the SEB grid may be banked for use at some other time within a certain agreed period. Under this mode also, the supply could either be to one's own units or to other units at the same or different location/s.

Banking charges should be reasonably low, not more than eight per cent of the energy supplied and should be recovered in the form of energy retained. The extra one per cent over the wheeling charge will compensate the SEB for retaining the power in the system. The price should, again, be mutually negotiated between the cogenerator and the end user, based on the ruling market conditions.

Standardization and Enforceability of Contracts

It is essential that 'national model' contracts are designed and enforced through appropriate legislations with the simplest possible rules and regulations.

A national contract prepared by the Ministry of Non-conventional Energy Sources (MNES) and the Ministry of Power, in consultation with the concerned parties, could be legislated by the Parliament as a central act. States wanting to encourage small producers of power could then enact their own legislations, based on the Central Act, with such changes as may be necessary to suit their individual situations.

Payment by SEB

Long-term assurance of payments by the SEB against amounts due in line with the agreed contractual terms is essential. This could be either through an irrevocable revolving, self-replenishing letter of credit or through an escrow account backed by the SEB's bankers. Either of these instruments could be operated through the bank account in which SEB receivables are credited.

Capital Investment and One-time Incentives

In cogeneration systems, only the incremental cost of the plant, the equipment, and other such capital costs should be regarded as capital expenditure for upgrading cogeneration facilities, resulting in the availability of net exportable power. The cost of upgrading process efficiency and energy conservation can, and should, be separately financed. For instance, in case of a sugar mill, this could be financed by the Sugar Development Fund (SDF). The cost of upgrading cogeneration systems in an existing sugar mill can be reduced by disposing the displaced plant and equipment to the new sugar mills experiencing shortage of capital funds and other interested buyers. The financing needs and the possible funding sources are outline below.

Feasibility Studies

The cost of feasibility studies for small power plants could be financed by grants from development financing agencies like the World Bank, the International Finance Corporation (IFC), the Asian Development Bank (ADB), the US Agency for International Development, the European Union, the Industrial Development Bank of India (IDBI), the Industrial Credit and Investment Corporation of India (ICICI), the Industrial Finance Corporation of India (IFCI), National Bank for Agricultural and Rural Development (NABARD), National Cooperation Development Corporation (NCDC), Ministry of Non-conventional Energy Sources (MNES), Indian Renewable Energy Development Agency (IREDA), and SDF.

This could be under a condition that if an assisted and feasible project is not implemented by the promoter, the grant given for the feasibility study will have be paid back to the financing agency.

Capital Investment

Once a project is finalized for implementation, funds should be made available on soft terms, as grants and/or low-interest term loans with a moratorium of at least two years and repayment over a period of 10 to 15 years. The pattern of financing could be made up from equity, debt, loans, and grants. The possible sources are listed below.

1. Equity

   - Promoters: major users, equipment suppliers, etc.
   - SEBs.
   - Central and state development/financial institutions.
   - The Power Finance Corporation (PFC).
   - Public issue.
   - IFC.
   - As debt in the form of debentures, fixed deposits, bonds, etc.

2. Loans: These are available from several agencies, namely, IDBI, ICICI, IFCI, NABARD, NCDC, SDF, PFC, state financial institutions, the World Bank, IFC, ADB, the United Nations Development Programme, the Global Environment Facility, the Greenhouse Gas Pollution Prevention Project, US EXIM Bank, European Union, etc.
3. Grants may be considered from MNES, IREDA and IFC, the US, the European Union, and other governments.

Session IV

Special Presentation

Cogeneration of Power[1]

Infrastructure Leasing & Financial Services Ltd[2]

Transparency 1

Widening Demand–Supply Gap

1. Total installed capacity: 78 900 MW; energy shortage of nine per cent
2. Eighth Plan target scaled down from 40 000 MW to around 19 000 MW due to budgetary constraints
3. Total available supply: 47 200 MW
4. Peak demand: 56 200 MW
5. Peak demand shortage

   - Present: 17%
   - Expected by end-1997: 20%

Transparency 2

Recent Developments in the Power Sector

1. Progress: though about 200 project proposals have been initiated since inception, few projects have achieved financial close.
2. Transmission and distribution has not been privatized so far.
3. The memorandum of understanding process is no longer valid; competitive bidding the order of the day
4. Focus shifts to delivered price

   - A number of state electricity boards are now fixing the off-take of power at a predetermined price from the power developer.
   - Consequently, a number of power developers have reduced their capital costs, to bring down the tariff to acceptable levels.

[1] Reproduced as presented at the conference, with minor modifications.

[2] Habitat Place, Lodhi Road, New Delhi - 110 003, India.

Transparency 3

Cogeneration. a way out

- Numerous obstacles faced by power developers in setting up new projects has led to a delay, thus worsening the power situation in the country.
- The current shortfall in demand can be effectively met by the existing process plants through cogeneration.
- Cogeneration is the simultaneous generation of heat and power using exhaust and waste gases.
- This power generated using cogeneration can be used for captive purposes within the plant.

Transparency 4

The Process

- Almost all industries need electric power as a motive force.
- Some industries like textiles, paper, food processing, and petrochemicals also require steam directly as an input for the process.
- Cogeneration can effectively serve the industry's requirements of power and steam.
- The sugar industry is most amenable to cogeneration as the by-product is bagasse, which is produced during the course of sugar production.
- This bagasse is used as a raw material for generating power.
- Industries like paper, cement, and chemical industries have the potential for power generation through cogeneration as heated waste gases are generated in the course of production.

Transparency 5
Types of Cogeneration

1. Cogenerated power can be produced in three ways

- Topping cycle
  - Power is produced initially.
  - A part of the thermal energy is used in process plants.
- Bottoming cycle
  - Recovers waste heat from the plant process.
  - This waste heat is used to produce steam for running turbines
- Combined cycle
  - Steam is generated from waste gases exiting from the turbine.
  - The steam recovered is used for running turbines and generating power.
  - Steam from the turbine is used directly for an industrial process.

Transparency 6
The Benefits

Capital cost: a cogeneration plant is about 25% cheaper than a conventional one.
Implementation period: a cogeneration plant can be set up and commissioned within 12–18 months.
Profitability: payback period of three years, at current state electricity board (SEB) off-take tariff rates.
Fuel conservation: lesser dependence on fossil fuels like coal, coupled with relatively pollution-free operation.

Transparency 7
The Obstacles

- The need for cogeneration has been increasingly felt due to the power shortage existing in the country.
- Steam required for cogeneration needs to be at a high pressure and temperature necessitating investment in large high-pressure boilers.
- In case the cogeneration plant is unable to consume all the power it generates, some part of power generated would have to be sold to the SEBs.

Transparency 8

The Incentives

1. Loans: the World Bank would fund cogeneration facilities in sugar factories in India to the tune of US $6 million. Funds would be channelled through a line of credit to the National Development Council.
2. Fiscal advantages
   - Cogeneration equipment has been classified as energy-saving equipment and is eligible for 100% depreciation.
   - Import duties on capital equipment have been reduced.
3. Subsidies
   - The Government of Karnataka is offering a subsidy of Rs 25 lakhs per MW to cogeneration units based on bagasse. This is in addition to the existing Union Government subsidy of Rs 70 lakhs per MW
   - The Ministry for Non-conventional Energy Sources provides a subsidy on loans sanctioned by financial institutions for the purchase of cogeneration equipment by sugar mills.

Transparency 9

Progress Made

1. Changes in the policies of several states in the form of incentives offered are inducing process industries to consider this option.
   - The Maharashtra government has fixed a rate of Rs 2.25 per unit as the price for the off-take of cogenerated power from sugar factories producing power in excess of 4 MW.
   - The Maharashtra SEB would hold equity up to 60% in such projects, with the sugar company having the option to buy back the equity against adjustment for sale of power.
   - Two sugar cooperatives each in Maharashtra and Tamil Nadu have set up cogeneration units.
   - Another 10–12 sugar cooperatives in Maharashtra are envisaged to set up cogeneration units soon with a capacity of 10 MW each.

Transparency 10

Cogeneration in Sugar Plants

- Existing sugar plants generate a substantial amount of by-products in the form of bagasse during the course of sugar production.
- During the sugar season, bagasse generated in the course of sugar production is sufficient to meet power generation requirements.
- Excess bagasse produced during the season is stored for power generation in the off-season.
- Bagasse is also bought during the season from other sugar mills for use in the off-season
- Exportable power *off season* > exportable power *in season* since captive demand *off season* < captive demand *in season*
- The power purchase agreement between the sugar company and the SEB needs to take into account the difference in exportable power during the year.

Transparency 11

Project Financing

1. As cogeneration plants are relatively small in size, financing is not perceived as a major problem.
2. Bankability of the project would be enhanced if the sugar plant enters into watertight agreements with various entities like SEBs, equipment suppliers, and operation and maintenance contractors.
3. A project lease could be an attractive source of funding in view of the 100% depreciation benefit to this sector.
4. The project could be domiciled in a special purpose vehicle (SPV) formed for this purpose. This approach entails benefits like:

   - ease of induction of strategic investors;
   - fiscal benefits in the form of tax incentives u/s 80 IA; and
   - the escrow arrangement between the SPV and the SEB so that:

     - the SPV has the first charge over SEB revenues; and
     - lessors realize lease rentals from the SPV easily.

Transparency 12

Future of Cogeneration

- It has been estimated that all the sugar factories in India put together can generate over 2500 MW of cogenerated power per year.
- Import duties on equipment need to fall further to attract industries in this area.
- Problems with SEBs in evacuating, banking, and wheeling power to demand centres need to be sorted out.

Session V

Cogeneration and Environment

International Financing Mechanisms and Cogeneration

A Damodaran[1]

Introduction

This paper discusses the relationship between international financing mechanisms, specifically the Global Environment Facility (GEF), and cogeneration. The GEF process was initiated in November 1990 in what is supposed to be a pilot phase. In 1994, after functioning for about two years, it was realized that this facility had to undergo certain modifications. Negotiations began for its restructuring, to make it more participative in nature, and to transform it from a rather closed group, after restructuring, into a universal participatory institution. Today, GEF has about 147 participating countries. The pilot phase was an experimental stage, where a lot of projects were taken up, amounting to about 1.3 billion dollars. However, what actually was spent was around 730 million dollars in about 115 projects in the world. The restructured facility has got a commitment of more than 2 billion dollars over a period of three years, to continue up to 1997/98.

The GEF Philosophy

The philosophy of GEF is different from the philosophy of a financial institution that funds environmental projects. It is a totally different facility and varies greatly from other financial institutions. The operating parameters and the norms and criteria of selecting projects are also different. GEF is supposed to provide new and additional grants or concessional loans to meet the incremental costs of measures to achieve agreed global environmental benefits.

Though this may seem rhetorical, it needs to be very clearly stated, that GEF, as an international financial mechanism to alleviate most of the global environmental problems, has essentially assumed a political shape. It is a political process with its economics get-

[1] Ministry of Environment and Forests, Paryavaran Bhawan, CGO Complex, Lodhi Road, New Delhi 110 003, India.

ting chiseled down in finer terms. The members of the GEF are the countries of the world. Projects proponents do not come forward and become members. Most of the donors, as well as recipients, are supposed to be equal partners in determining how GEF resources should flow. There is, therefore, a very great emphasis on country-driven projects. There is no project which should be imposed from outside. One does not sit, say, in London and decide that certain products are to be implemented in India. Projects are generated within the country and project priorities are nationally determined. However, these priorities are made to fit into a global agenda.

The forceful foresight of GEF activities relate to the Framework Convention on Climate Change (FCCC), the Convention on Biodiversity, and the Convention on Ozone Protection and International Waters. International waters is not, strictly speaking, a uniform convention. It is not a convention-related obligation. GEF is considered to be a financial mechanism – as a temporary financial mechanism – for the FCCC There are, therefore, certain obligations which arise from its status as a temporary financial mechanism under the FCCC, which makes it mandatory to receive the guidelines of the Conference of the Parties, that is the countries that have signed the Convention while sanctioning projects under climate change. In the context of cogeneration, it is climate change that is supposed to be the concerned convention, and which concerns the GEF. GEF also funds, apart from convention-related projects, non-convention related projects, where the GEF council, consisting of about 34 countries, has to discuss and provide guidelines on the kinds of projects that are to be chosen for funding under GEF.

Basic Principles of GEF

As far as incremental costs are concerned, the terms used are agreed and full – what is relevant here for cogeneration is again the FCCC, with the agreed terms very explicitly mentioned in Article 4 of the FCCC. There is a fairly long statement on incremental costs – agreed and full incremental costs – i.e., the additional costs in terms of not only the technology but also the infrastructure expenditure pattern policy in comparison to a baseline non-global benefit project. An agreed and full incremental cost is supposed to be not just the incremental cost of investing in globally environmental benefits, or in a project which leads to global environmental benefits, but it also includes the compliance costs – the compliance costs related to the convention and the compliance costs related to the provisions of the convention, which, in turn, are related to the project.

As far as local and global environmental effects are concerned, GEF is supposed to cater only to global environmental benefits. Global environmental benefits, in keeping with the Climate Change Convention, would mean achieving reduction in emissions of carbon. That is what GEF is supposed fund – the incremental cost necessary to achieve carbon emission reduction. Therefore, GEF is not concerned about basic issues that are specific to a nation or lead specifically to national benefit.

What does agreed global environmental benefit mean? If it is felt that a particular cogen project will have a very significant effect, say, on the way land has to be managed for solid waste management for example, it then has to be segregated and accounted as distinct from the global environmental benefit of reducing carbon emissions. That is where one must have an agreement on global environmental benefits and where one needs to have an agreement on what constitutes the incremental costs of these benefits.

The chief principles of GEF are, therefore, centered around incremental costs and the agreed global environmental benefit. GEF resources amount to just 2 billion dollars, and there are 147 countries theoretically bidding for it for various resources. As it cannot meet all these demands, it has to stretch a little far, and has to be selective in the choice of projects which its funds. Hence, it employs the principle of cost-effectiveness as well – it looks for the least-cost method for attaining global environmental objectives, both by technological assessment and policy interventions. In a nutshell, this means that incremental costs do not just involve economic costs; they involve various other issues as well, which need to be kept in mind while considering the incremental cost of a particular project.

Let us assume that a typical financial development financial institute is to provide loans to prospective parties who apply for funds for cogeneration projects. What do they look for? There are two or three very obvious criteria, and one is the return on capital. They have a concept of how much return on capital should exist and will agree to fund the project on those terms, say at 20% return on the capital of the project. GEF does not ask this question. This is the difference between GEF and other such financial institutions. GEF queries only as to why is the rate of return (RoR) cannot improve from, say, 2 to 20%. And, that it will fund only those projects which have the potential of raising the RoR from, say, 2% to the optimum 20%; whereas a financial institution will typically reject any project which does not fit into the economic criteria of the return of capital or of the payback period.

GEF Operations

GEF operations can be characterized into three streams; the first stream involves long-term operational projects – i.e., typical projects like demonstration cogen plants being put up in some country; these are considered as operational programmes, and are supposed to operate in the account. Then there are the enabling activities – national communications, inventory of greenhouse gases (GHGs), and so on.

Finally, GEF also funds under the recent operational guidelines. They have decided to fund short-term projects that provide discernable immediate benefits at low costs. One example which the GEF documents themselves cite is the use of liquefied petroleum gas (LPG) as fuel in the future. However, on going though GEF portfolios, one will notice that 70% of the funds has been, and will be, committed to long-term operational projects. That is where the cogeneration projects have to figure, as long-term operational projects.

Where does cogeneration, therefore, come into the GEF scheme of things? GEF has two basic principles. When a project is submitted, the issue is not the RoR. The issue lies in the barriers that prevent the RoR from increasing. And, they will fund only such projects that show the promise of substantially raising the RoR. What, therefore, are the problems normally encountered in getting funds for a project that does not fit into a high RoR category? Typically, there are certain barriers – barriers that GEF talks about removing – implementation barriers to energy conservation and efficiency. For instance a cogen plant for, say, a less than 2500 tonnes per day sugarcane mill, is not an economic proposition. In fact, there will be a lot of cash outflow problems at the initial stage and a low RoR as well. This, therefore, is an implementation barrier, as such a disbursed small volume bagasse-generating sugarcane mill cannot have cogeneration facilities. GEF is

supposed to look into such implementation barriers and identify the exact problem. GEF has to look at the large-scale application and dissemination barriers as well. For example, to set up a 3500 MW plant, it would need to identify the dissemination barriers involved – is there a problem with every sugar mill; what are the problems that every sugar mill faces in getting the technology disseminated, and so on? GEF has to also look at reducing the long-term costs of low greenhouse gas energy technologies. Here again cogeneration figures. Because, if the long-term costs of cogeneration have to be reduced, GEF has to consider those proposals and support them.

Finally, where do the incremental costs come in? Incremental costs, as mentioned before, are not just the costs of investment. It is also the cost of all the concomitant policy and expenditure pattern changes. In this case, while considering a cogeneration plant as a proposal for GEF assistance and the barriers which prevent other financial institutions from supporting it, i.e., the incremental costs, GEF is supposed to fund such projects and remove such barriers.

Specific GEF Projects

Three very outstanding examples of GEF-funded projects can be found in: (i) Brazil (with a government agency implementing the project); (ii) Mauritius; and (iii) Morocco.

The Brazil project involves biomass-integrated gasification. It has the United Nations Development Programme as the implementing agency and is operated through the government national utility in Brazil. The Mauritius project on bagasse energy is a World Bank cum GEF project, and is co-financed by the World Bank. The Morocco project is, again, a co-financed project of the World Bank and the GEF, and centres on public utilities.

As a note of caution, one should add that Article 28 of the GEF – the restructured GEF – clearly provides for private sector participation in its programme. There is absolutely no bar on it. Whether it is a multilateral bank or a donor, each one can submit project proposals which can be considered for funding. The International Finance Corporation is also playing a very important role in ensuring that there are co-financing opportunities available for private sector/GEF co-financed projects.

Taking up the Brazilian project in detail will provide a fairly good idea about how the incremental cost concept operates. It is supposed to be a demonstration project, a prototype unit, on a commercial scale, and proposes technical assistance for building a demonstration project. The outstanding features of this project include an emphasis on the use of gasified biomass of low calorific value to generate power through gas turbines (both wood chips and bagasse are considered); improving boiler capacity through the use of fluidized bed combustion boilers; the use of aeroderivative gas turbines to enable to a better efficiency in the conversion of low calorific value gas; and, very important, the utilization of a utility power purchase agreement or tariff adjustment. This is exactly what the GEF is about. The GEF stresses on all these points. It will also create facilities to ensure that the improvements in technology achieved at the boiler stage or at the turbine stage is equally translated into a sustainable one by influencing the tariff structure. This project will demonstrate that, GEF, as and when it starts yielding power, pays a lot for the Brazilian government to revise the tariff or provide a tariff structure which is

equal to the avoided cost of generating fossil fuels. This is not true in the case of any other development/financial institutions.

To narrow down the issue, what would the GEF look for in Indian projects? Taking up a project on cogeneration, for example, the first issue will concern the principal constraints to more efficient cogeneration in the country; to optimizing power production from, say, biomass; to improving boiler efficiency; to replacing back-pressure turbines by condensing turbines; and so on. All these are the principal problems. There is then the absence of multi-fuel boilers for year-round operations. There are, however, many who contest the claim that year-round operations will substantially improve the return on capital. This is a problem. If bagasse is available only 180 days in a year, then boilers which can use other secondary fuels like coal or lignite would be essential. Therefore, the emphasis is, again, on multi-fuel boilers. Then comes the need to enhance the process steam, i.e., to reduce the process steam requirements so that more steam goes into production of power. One would then need technologies for turbines and turbine generators to overcome the problems of 11 kV or voltage transmission lines which will create grid frequency. These are the local problems that will have to be overcome. Also, very few people refer to the low calorific value of bagasse. For instance, wet bagasse is supposed to constrain efficient cogeneration.

As far as GEF is concerned, all the other requirements, except the multi-fuel issue, are fine. The moment you talk about multi-fuel boilers, which seek to use bagasse for 180 days in a year and then use coal or lignite for the remaining period of the year, you are going to face a serious problem in getting funding. This is because the carbon emissions problem caused by the use of coal or lignite cannot be supported by GEF as it goes against the very spirit of FCCC. The three projects mentioned earlier, in Morocco, Mauritius, and Brazil, all have limited problems. Their problems do not start right from the fuel upstream, that is right from the fuel quality; they only start from the boiler downwards. There is, however, a lot of scope for getting an integrated project, starting right from the sugarcane fields using agro-based fuel or any agriculture residue.

Policies of the US Initiative on Joint Implementation

David Hess[1]

Introduction

The Government of India, and the Ministry of Environment and Forests, need to be commended for instituting an exclusive office for the Global Environment Facility (GEF) within the Ministry, for supporting and funding projects, and for coordinating the implementation of investments in climate-friendly technologies and in the preservation of biodiversity. This initiative is an indicator of the Indian government's serious commitment to overcoming barriers to high-grade environment-friendly investments in India and to establishing a national sustainable development strategy as seen in its environmental action plan.

A few years ago, USAID developed what was for the US government its largest global warming project under the pilot phase of GEF. It is located in India and is being implemented now. It is called the Greenhouse Gas Pollution Prevention Project. This project has two major components. The first component involves more efficient coal conversion, and works on improving the efficiency of existing thermal, coal-fired power plants.

The larger component in the project is called alternative bagasse cogeneration. Under that component, we are taking a complete systemic approach of supporting the takeoff of commercial scale investments in more efficient electricity generation by sugar mills, much of which will be sold to state electricity boards' (SEBs) grids and will augment and displace power generated from fossil fuels. We want to see at least six or seven commercial-scale demonstration projects in bagasse cogen, using high-pressure boilers and high-efficiency turbines that use only biomass year-round. This is a challenge – a challenge that at least 12 major sugar mills have already taken up, and for which they have also applied for the first round of grants.

Worldwide concern about the rapid degradation of the earth's climate, and about global warming, initiated dialogue and activities in joint implementation (JI) at the 1992 Earth Summit at Rio. The concept of JI was then formally adopted into the text of the

[1] Office of Environment and Energy Enterprise, US Agency for International Development (USAID), American Embassy, Chanakyapuri, New Delhi - 110 021, India.

United Nations Framework Convention on Climate Change (UNFCCC). The US, along with more than 150 countries, signed that convention. This convention requires its signatories to meet their obligations and reduce greenhouse gas (GHG) emissions jointly with other parties. JI, therefore, involves a wide range of possible arrangements between entities in two or more countries leading to the implementation of cooperative development projects that seek to reduce avoid GHG emissions; the need is to join together and do all that can be done to reduce GHG emissions.

The first meeting of the Conference of Parties was a historic event, and took place about a year ago between 28 March and 7 April 1995 in Berlin. At this meeting, a decision was made to establish a pilot phase for activities implemented jointly (AIJ as it is referred to in the parlance of the international people among parties to the convention). Under the strong leadership of the then Minister Kamal Nath, the team from Ministry of Environment and Forests, Government of India, played a very crucial role in these deliberations. The pilot phase discussed then would, by the year 2000, provide an excellent opportunity to demonstrate the viability of JI as a practical and equitable strategy for meeting the objectives of FCCC. It is here that the US Initiative in Joint Implementation (USIJI) plays an important role.

USIJI

Launched in October 1993 as part of President Clinton's Climate Change Action Plan, USIJI is the largest and most developed programme being created worldwide to explore the potential of JI. A flexible, non-regulatory programme that encourages private sector participants in the US to engage in overseas projects in order to reduce net GHGs, the programme provides public recognition and limited technical assistance to participants in approved projects.

USIJI is administered by its inter-agency secretariat chaired by the US Environmental Protection Agency (EPA) and the US Department of Energy (DoE), with significant participation by USAID. Other participating agencies include the Departments of State of Agriculture, Commerce, Trade, and Treasury.

Objectives of USIJI

The objectives of USIJI are outlined below.

1. To encourage the development and implementation of cooperative, cost-effective, voluntary projects between the US and foreign partners, especially those that promote technological cooperation and sustainable development.
2. To promote projects to test and evaluate methodologies by measuring, tracking, and verifying cost and benefits.
3. To contribute to the formulation of international criteria for JI for faster private sector investment in the innovation, development, and dissemination of technologies for reducing GHG emissions and encouraging bagasse-based cogeneration.
4. To encourage participating countries to adopt more complete climate action programmes, including nationally implemented baseline policies, measures, and appropriate specific commitments.

Purpose of the USIJI Pilot Programme

The main purposes of the USIJI pilot programme shall be to:

- encourage the rapid development and implementation of cooperative, mutually voluntary cost-effective projects for US and foreign partners, that either reduce or sequester GHG emissions particularly projects that promote technology cooperation with, and sustainable development in, developing countries, with economies in transition, or market economies;
- promote a broad range of products to test and evaluate methodologies for measuring, tracking, and verifying costs and benefits;
- establish an empirical basis to contribute to the formulation of international criteria for JI and freely encourage private sector investment and innovation in the development and dissemination of technologies reducing/sequestering emissions of GHGs; and
- encourage participating countries to adopt more complete climate change action programmes, including nationally implementable baseline policies and measures and appropriate specific commitments.

Administration of USIJI

An inter-agency working group, as mentioned earlier, is responsible for overall policy development and decisions on amendments to programmes and ground laws in formulating the international strategy for promoting JI. The Evaluation Panel (EP) of the programme is an independent technical review body, comprising representatives from various agencies – DoE, EPA, USAID, and the Departments of State of Agriculture, Commerce, and Trade and Treasury. EP makes the final decision on projects that qualify for the USIJI status. It has the discretion to approve operational protocols and methodologies in implementing evaluation criterion. The Secretariat supports EP on the day-to-day operation of programmes, including sourcing, receiving, and reviewing project applications.

Processing of Projects

Beginning in October 1994, EP began accepting proposals to be processed for approval. The Secretariat, which receives proposals, conducts the preliminary reviews, and contacts, if required, applicants for clarification or additional information, makes efforts to review all the applications within 90 days. Based on the proposals the Secretariat reviews, EP selects the portfolio of projects representing a broad range of approaches in different geographic regions. After completing its preliminary review, the Secretariat provides the portfolio of projects to EP, with detailed recommendations for individual approval or rejections. The Panel then makes the decision on the projects, and approves the portfolio. The Secretariat then, in turn, initiates the process of funding. Accepted projects receive specific certificates for recognition and further instructions for reporting under the programme, and may be invited to participate in public recognition events sponsored by the panel. The Panel also advises those project applications that have not been accepted on revisions to be made for future acceptance.

Benefits of USIJI

The benefits of USIJI for the US participants include: (i) input developments of international criteria for JI, and information on participant projects that contribute to the development of the international programme on JI – i.e., projects that provide vital inputs for the further development of any future US programme on JI, tracking and coding of emissions reduced and sequestered by USIJI projects, etc.; (ii) public recognition for their efforts to reduce the threat of climate change and contribute to sustainable development; (iii) technical assistance provided by the Panel – a limited amount of general technical assistance, substitutable resources, and the development of an appropriate mechanism in the form of workshops, guidance documents, papers examining specific issues, and hotlines; and (iv) access to new market opportunities. Global markets for new technologies and energy and natural resources management is growing rapidly. As a viable part of the sequestering programme, market survey data and other information, including that on existing export opportunities, are provided to USAID and other federal agencies.

The benefits to foreign participants include: (i) technology transfer – the USIJI pilot programme will encourage additional US power sector investment in the dissemination of innovative technologies that can help meet development priorities for reducing or sequestering GHG emissions, in other words, meeting economic criteria, and local and environmental benefits; (ii) by reducing transaction costs, USIJI would invest in technologies and projects to reduce GHGs and contribute to overall host country developmental objects; (iii) local environmental and human health benefits – measures that reduce/sequester GHGs often generate other local, environmental, and human health benefits by preventing/reducing air and water pollution and by contributing to the more suitable use of natural resources; (iv) local economic benefits – USIJI projects may generate local economic benefits through new and improved facilities, public participation projects, and provision of new energy services; and (v) global benefits through the reduction of GHG emissions. GHG emissions are projected to grow at an alarming rate on a global basis. JI offers cost-effective opportunities to reduce/sequester emissions of these gases and, therefore, promote sustainable development. The demand for clean energy services and natural resources in some developing countries, specially in the countries with economies in transition, is outstripping currently available supplies, resulting in potential shortages and environmental degradation. USIJI will encourage additional private sector investment in the development and dissemination of technologies that contribute to sustainable development or reduce/sequester GHG emissions.

Criteria for Projects under USIJI

Section 5 of the final USIJI ground rules, as published in the Federal Register in the US in 1994, outlines the criteria for selection proposals that can qualify for USIJI. These criteria state that the project:

- is acceptable to the government of the host country;
- involve specific measures to reduce or sequester GHG emissions initiated as a result of USIJI or in anticipation thereof;

- provides sufficient data and methodological information to establish a baseline of current and future GHG emissions (part of that is in the absence of specific measures referred to above which must reduce/sequester these emissions;
- reduce or sequester GHG emissions beyond those referred to above are...
- contains adequate provisions for tracking the GHG emissions reduced or sequestered resulting from the project, and that, on a periodic basis, the project would need to be modified by comparing actual results with those originally projected;
- contain adequate provisions for the external verification of the GHG emissions reduced or sequestered by it;
- leads to certain associated non-GHG environmental impacts and benefits;
- provides adequate assurance that the process of reduction or sequestration of GHG emissions will cease or get reversed; and
- provides all its reports to EP on emissions reduced or sequestered to both the domestic and foreign participants, in keeping with the terms of the voluntary agreements among the participants.

In determining whether to include projects under USIJI, EP also considers the potential for the project to lead to changes in GHG emissions elsewhere in other countries; the potential positive and negative effects of the projects apart from their effect on GHG emissions reduced or sequestered; the fact that whether the US participants are emitters of GHGs within the US and, if so, whether they are also taking measures to reduce or sequester such emissions in the US; and whether efforts are on within the host countries to ratify the FCCC, develop a national inventory and a baseline of GHG emissions by sources, to adopt measures to reduce emissions.

Achievements of USIJI

The draft USIJI ground rules were announced in December 1993 through numerous publications. They were also distributed, in September 1994, at a one-day workshop held in Washington, DC. Post-grant proposals received in November 1994 were evaluated and seven were selected according to USIJI criteria. These seven successful projects were announced by the Departments of State only a year ago. The additional proposals that benefitted farmers by providing economic benefits acquired further project development benefits. USIJI and its sponsoring agencies have obtained joint statements of intents in several countries. One such statement was signed by the US Vice President and the Costa Rican President in 1994. The second round of proposals closed on 28 July 1995. Of the 21 projects that were submitted then, eight have been announced as successful in January 1996.

USIJI is the first and the most developed programme worldwide. Its other international activities and workshops, attended by several hundred participants from across 40 to 50 countries, have positively influenced international understanding on JI and the FCCC. Other countries, including Canada and Australia, have announced further JI efforts closely modelled on USIJI.

Future Targets

USIJI is completing a technical assistance programme to develop specific guidelines that assist selected projects in emissions accounting, monitoring, and verification. Additional proposals will be solicited sometime later this year. USIJI expects to shortly solicit host country involvement in proposals and assist participants in obtaining project finance through the US Export and Import Bank, the US Overseas Private Investment Corporation, and other financial institutions.

The question that arises now is: of what importance is USIJI to India? USAID has always responded positively to the changing demands of the Indian investment sector, especially in energy, and is also working on climate-friendly investments. There are several opportunities for cost-sharing of investments in projects, especially in GHG pollution prevention, or, more specifically, in the alternative bagasse cogeneration component. Between 1982 and 1992, USAID supported an R & D programme in alternative energy resources. The primary focus of that programme was to develop new and advanced coal and biomass conversion technologies for the efficient utilization of the abundant coal resources and biomass feedstock in India. The programme for the acceleration of commercial energy research, and energy management and consultation, continues to support the development of advanced energy efficiency and cogeneration technologies. It has worked with appropriate government institutions in removing policy barriers for effective implementation of these technologies. USAID is also working with financial institutions, notably the Industrial Credit and Investment Corporation of India and the Industrial Development Bank of India to encourage those development financial institutions to get into the business in a big way in financial cogeneration.

USAID's Role in USIJI

USAID plays a significant role in the USIJI Secretariat and would like to work closely with Indian institutions as they work towards finalizing the methodology for implementation of pilot phase JI projects through Activities Implemented Jointly or AIJ, especially if they involve the global Environment Facility. Mention must be made of the commendable initiative of our JI network in the Netherlands for planning to hold a regional conference with Development Alternatives of India in New Delhi in January 1997 for developing countries to discuss the role of private sector capital in the pilot phase of the JI programme. We intend to participate strongly in that Netherlands–India initiative, which intends to assess the needs to strengthen professional institutional capacity in the host countries for the effective implementation of JI. USAID has played an important role in developing and finalizing this conference.

AIJ presents a sure win-win situation, and there is a very clear signal that should be sent to India, especially for the implementation of baseline efficiency 'upgraded power projects in coal-powered power plants, in the electricity sector, in industrial cogeneration, as well in bagasse cogeneration. A baseline project is a typical project that could have been dealt with even in the absence of J. 'Efficiency upgrade' – the terminology

coined by the International Energy Agency – has the potential to create more environmental-friendly international investments and additional power generating capacity in the exponentially growing economy. The exclusion of crediting does not have to necessarily reduce the number of JI projects being put forward for consideration, as power projects normally require lengthy planning procedures.

Thus, by the end of the pilot phase, in other words post-2000, considerable investment in host countries and experience would have been built up, and negotiations for JI projects could well be on top of the learning curve. JI has the potential to increase the amount of foreign financing available for power sector development, which allows the financing of more efficient technologies.

Pending Government of India clearance, some of the projects that are already been evaluated and qualified by the USIJI secretariat include the proposal by the Consortium of Appropriate Technology, Washington, DC, and the AES Corporation in Virginia, in association with the National Dairy Development Board of India, for GHG emissions reduction through enterprise development and for improved livestock feeding for small-scale dairy producers on the State of Gujarat, India. It seeks to introduce alternative cattle farming, both in nutrient molasses and urea bottling, which would cut down global methane emissions from rural livestock up to 12%. There is also a project in the area of bagasse cogeneration, which is also in very advanced stage of discussion, both in terms of USIJI and AIJ.

Conclusion

AIJ, therefore, is definitely, a potential win-win opportunity; a win for the global environment as emissions are reduced/sequestered; a win for the local investors, project developers, non-governmental organizations, and foreign investors, through additional incentives, and through the creation of investments in more climate-friendly and environmentally-friendly, and higher end-efficiency technologies, which would, eventually, qualify for JI as countries work out the credit-sharing structure.

Session VI

Cogeneration Technologies

Steam Turbine Options for Optimizing Cogeneration Applications

C N Nath[1]

Introduction

In the context of today's energy scenario, especially in India, where energy costs are increasing, availability of power from grid is not assured, and the gap between demand on and supply from installed capacities is widening, it is imperative for new industries to plan for captive power generation. For industries where the requirement of steam for process also exists, like in the fertilizer, paper, petrochemical, and sugar industries, cogeneration of power and process steam is the obvious choice.

As an example, a typical application of cogenerating a given level of heat and power separately, and in the cogeneration mode, are compared in Figure 1. Separate generation as at 'A' uses a straight condensing turbine for generation of power and a low pressure (LP) boiler for the generation of steam required for meeting process heat. 'B' is the cogeneration mode to meet the same requirements. The primary fuel requirement in mode 'B' is 15.3% less. This benefit accrues in cogeneration due to the integration of steam generation at high parameters and reduction of heat rejection to the atmosphere as the base Carnot cycle efficiency improves. Further, gains are realized by the careful study of the thermodynamic layout of the system, and the use of the state-of-the-art concept for building the turbine.

Basic Efficiency

The basic efficiency for a thermodynamic cycle is defined below.

$$ETA = 1 - \frac{T_2}{T_1}$$

[1] Bharat Heavy Electricals Limited (BHEL), BHEL House, Siri Fort, New Delhi - 110 003, India.

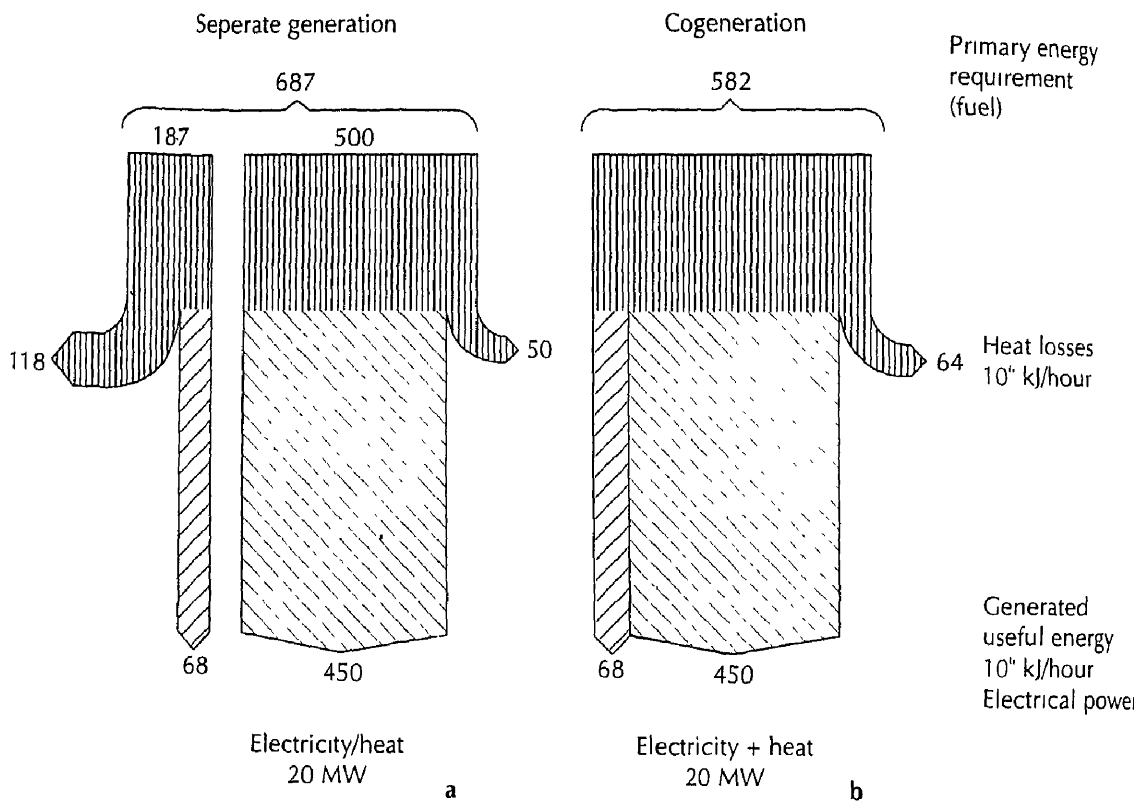


Figure 1. *Comparison of the primary energy (fuel) requirement for the generation of 450 10^6 kJ/hour and 20 MW electrical power;* ***a*** *with production in separate plants;* ***b*** *with cogeneration*

where 'ETA' is the Carnot cycle efficiency, which is the highest thermodynamic efficiency possible when operating between two temperature levels; 'T_1' is the temperature which the heat addition to the cycle takes place; and 'T_2' the temperature at which heat rejection from the cycle takes place.

It is evident from the equation that a higher temperature at the inlet and a lower temperature at the exhaust results in higher efficiency. This is why the system designer always looks for higher parameters, costs permitting. Even though in the 1950s there have been plants with very high parameters, of the order of 300 ata and 600 °C, the operational and maintenance difficulties have restricted these to the level of 140 bars/540 °C for industrial applications. These problems have largely been overcome today due to metallurgical developments in steel for high temperature use, advanced computer techniques for thermal stress analysis, etc. This brings in the option, for the enterprising client, of higher temperature solutions, with the resulting incremental gain in efficiency. Recently, at BHEL, we have designed and put into service a back-pressure turbine for Tata Chemicals Ltd, Mithapur, with an inlet temperature of 570 °C at 106 bars. Here, the incremental gain in efficiency was justifiable with a payback period of about three years for the difference in investment. For the lower temperature T_2, the limitations occur due to the ambient conditions available at a given site. The lower the ambient temperature, the lower is the cooling water temperature considered for the design, resulting in lower

vacuum in the condenser. For the process industry, where heating steam requirements exist, the quantity of steam which goes to the condenser can be reduced by taking extractions from the turbine. The limiting case is the back-pressure turbine where no condenser is involved and efficiencies of the order of 90% are possible.

Process Steam Demands

The process steam demands are very specific for a given industry and the capacity of the plant envisaged. The steam flow and the pressure and temperature levels are dictated by the equipment at the consumption point, and, hence, the pressure levels required from the turbine are fixed. Table 1 gives the typical range of pressure levels required to be met by the turbine for extraction and exhaust steam.

Integrated Approach

The endeavour of the system designer is to integrate the process steam demands and power demands – either electrical power or power for mechanical drive applications – in the best possible manner in a steam turbine, keeping in view the consideration for high basic efficiency. The ideal solution is a back-pressure turbine (Figure 2). If the steam demand is such that less power is produced than is required, a condensing portion will have to be used. This results in the lowering of efficiency, though it attains the desired balance of power and steam requirements. This solution is achieved by using a condensing turbine, with the extraction of steam from the turbine casing at an appropriate level.

Options for Extraction

The extraction of steam from the turbine can be done in two ways.

1. Extraction of steam at the desired pressure level and throttling the steam flow to the condensing part of the turbine in a throttle valve for controlling the pressure (Figure 3). This is known as controlled extraction.

Table 1
Typical range of pressure levels to be met by turbine

Industry	Process steam pressure
Fertilizer/petrochemical	40 ata HP[a] steam; 25 ata MP[b] steam; 5 ata LP[c] steam;
Paper/fibre	10 ata HP steam 5 ata LP steam
Sugar	1.5 to 2 5 ata

[a] high pressure; [b] medium pressure, [c] low pressure

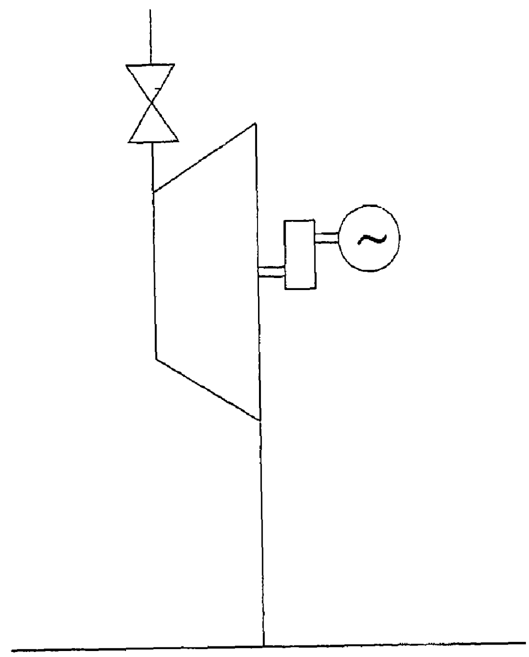


Figure 2. *Back-pressure turbine*

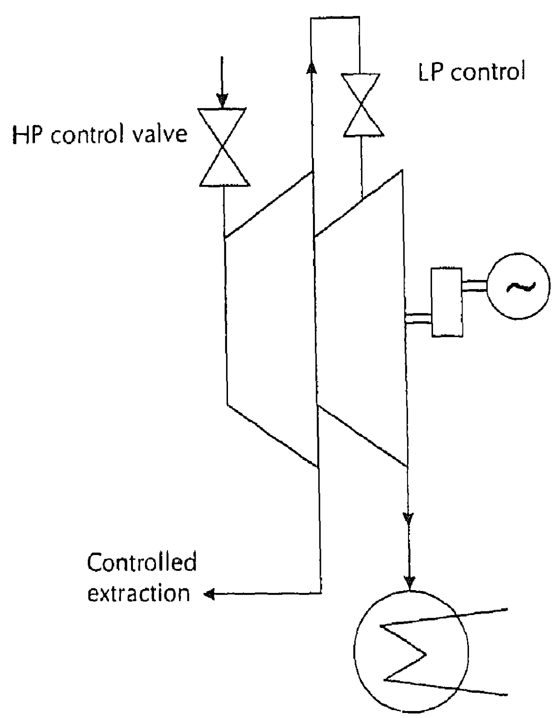


Figure 3 *Extraction condensing turbine*

2. Extraction of steam at a higher pressure from the turbine and throttling it to desired pressure levels in the extraction line (Figure 4). This is known as externally controlled extraction.

In the first case, the steam turbine is required to be divided into HP and LP parts by using an intermediate gland for isolation, and the LP control valves of appropriate size mounted on the turbine.

In the second case, the turbine is a straight condensing turbine with a gap between stages at an appropriate location and a corresponding opening in the casing for tapping the extraction steam. As pressure is controlled in the extraction line with the help of the pressure control valve, no turbine mounted valves are necessary.

The choice of the solution adopted depends on the quantum of steam required to be extracted. Generally, where quantities of steam to the condenser are less, controlled extraction is the better option, and, where quantities of steam to process are less, externally controlled extraction is the better choice. As an example, the case of a steam turbine with steam parameters as given in Table 2 is considered for analysis.

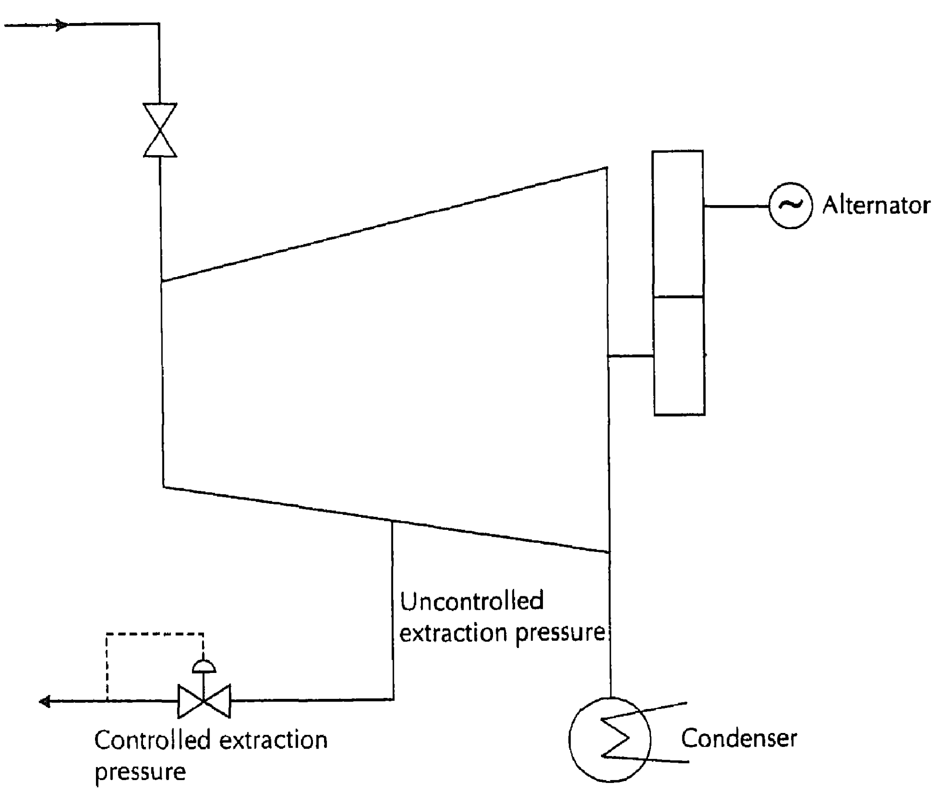


Figure 4. *Condensing turbine with external control for extraction*

Table 2

Steam parameters for analysis

Parameters	Quantity
Inlet pressure (ata)	65 0
Inlet temperature (°C)	480.0
Inlet steam flow (kg/second)	9.0
Extraction pressure (ata)	5.0
Exhaust pressure (ata)	0.1

For a given inlet steam flow, the extraction quantity is varied from 10 to 50%. The corresponding power generation in a turbine with internal control (i.e., the throttling flow to the condenser) and a turbine with external control (throttling flow to process) are compared in Figure 5.

In the case of external control, the pressure at the tapping point on the turbine casing is considered to be 10 ata, so as to allow extraction of steam at five per cent part load operation also, that is a turn-down of 50%. It can be seen from the curves in Figure 7 that up to 18% of inlet quantity as extraction, external control is better than internal control (the point of intersection of curves A and B). If the turn-down is reduced to 10%, then the cut-off point shifts to 39% of inlet flow (the point of intersection of curves A and C).

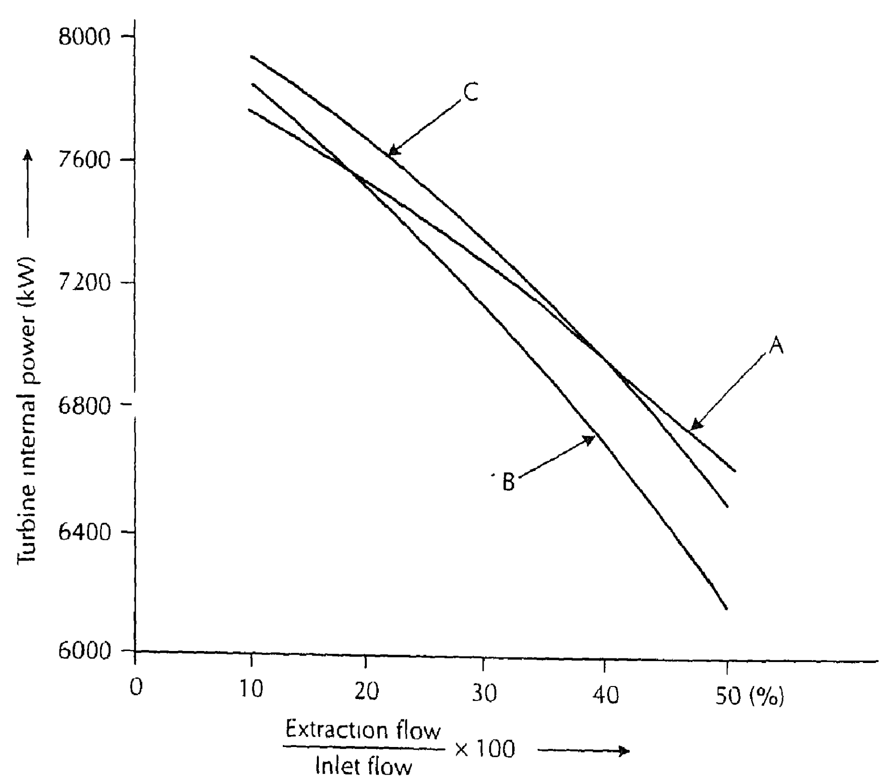


Figure 5 *Selecting steam extraction pressures; Curve A. turbine with controlled extraction, Curve B· turbine with external controlled extraction and turn-down ration = 50%; Curve C turbine with external controlled extraction and turn-down ration = 10%*

Wander Extraction

For achieving greater turn-down when extraction steam flows are not very high with reference to inlet flow, a straight condensing turbine is used with two or more tapping points for extraction. The pressure at the lowest extraction point is decided to meet a turn-down ratio of say 1:10. Then, for operations below 9:10, load pressure at this point will not be adequate for meeting the pressure, and the steam will be tapped from the next extraction upstream (Figure 6). This transfer of extraction tap-off from one point to another can be done smoothly using microprocessor-based wander control. A typical application of this solution was successfully adopted at FEDO, Cochin, for a 10 MW extraction turbine supplied by BHEL. Adopting uncontrolled wander controlled extraction turbines will result in simpler consideration and lower costs, in addition to gains in efficiency at lower turn-down ratios.

Turbine Construction

With the steam parameters, power, and range of operations specified by the user, it becomes the task of the turbine manufacturer to select and build a turbine to achieve the best conversion efficiency, with the highest reliability. The modular system based on building block principle is used by BHEL towards achieving this objective. The basic sys-

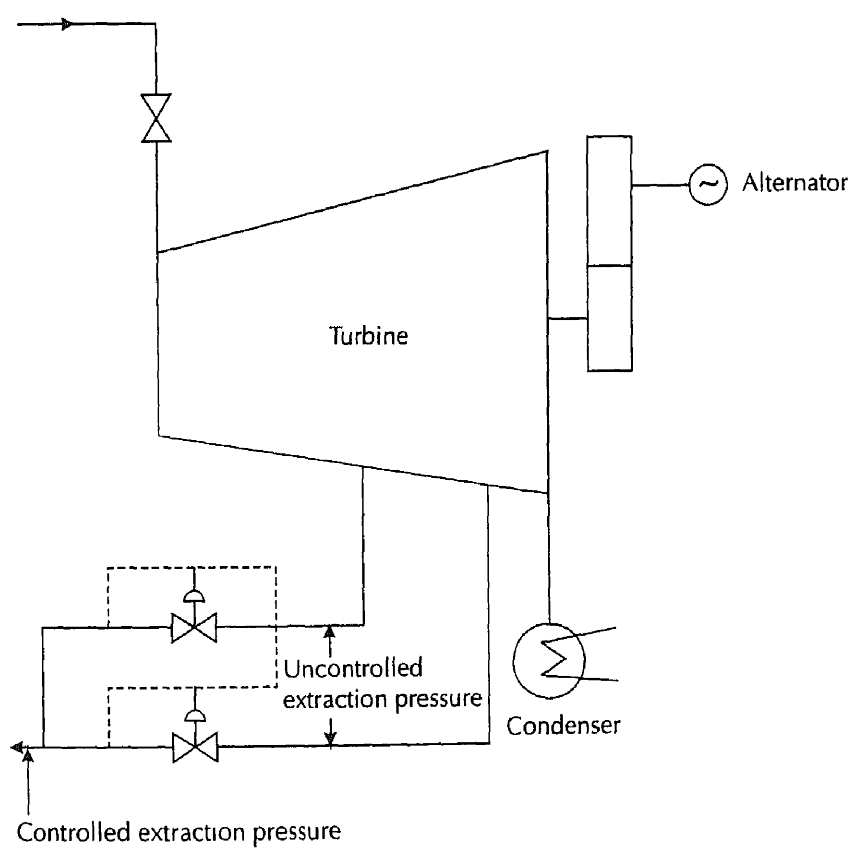


Figure 6. *Wander controlled extraction*

tem adopted from Siemens of Germany envisages the use of standard and proven modules with total flexibility in configuring the thermodynamic flow path.

The standard modules comprise of inlet sections, bearing housing, bearings, exhaust sections, stop and governing valves, servomotors, last stage blades, etc. Figure 7 depicts the general concept involved. The appropriate sizes of front, rear, and middle portions are selected and joined to form a steam turbine optimum for a specific application (Figure 8). For each machine configured, the thermodynamic design is done, using computer programs for optimizing the blading and flow path components. Subsequent to the thermodynamic design, rotor dynamic analysis is done, again using computer software capable of simulating various modes of operation. Correction of the geometry chosen is done, where required, to result in a stable configuration.

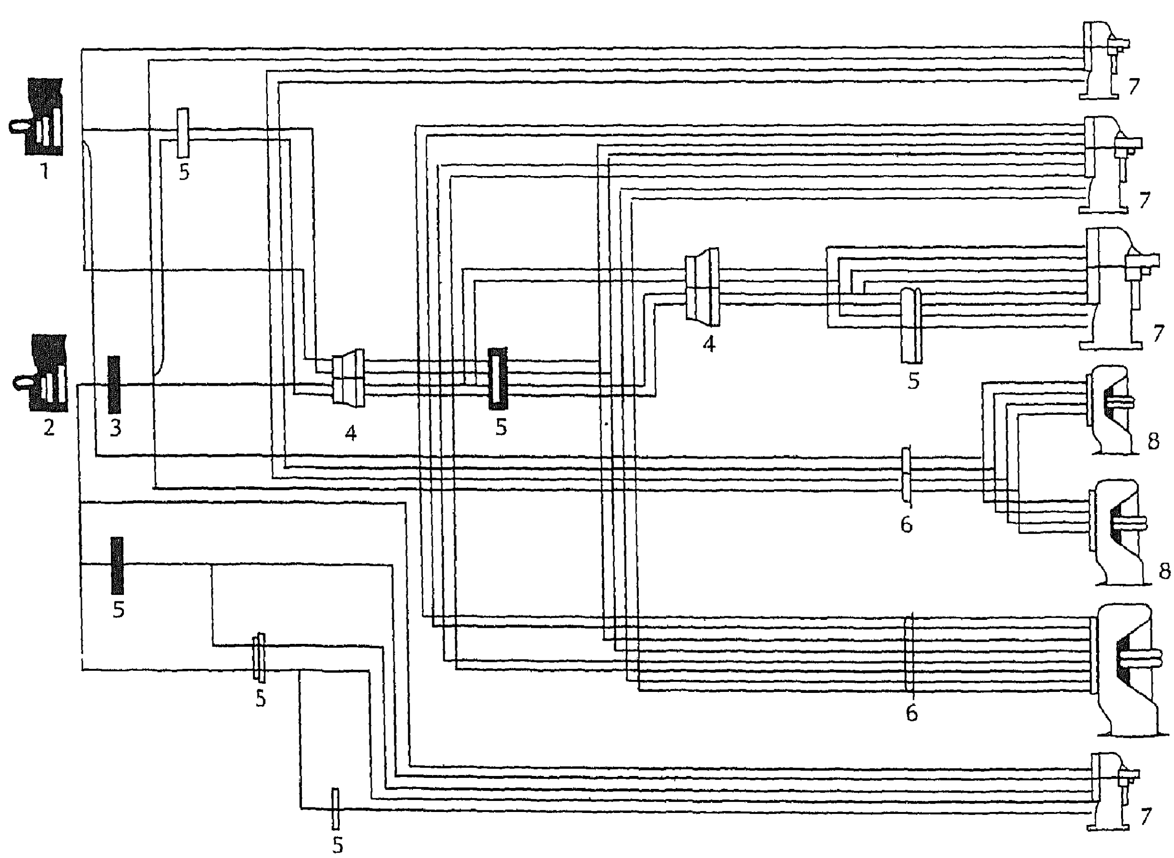


Figure 7. *Building block section; 1: admission section N; 2: admission section H; 3: reducing section; 4: transition section; 5: extension section; 6: flange section; 7: exhaust section backpressure turbine; 8: exhaust section condensing turbine*

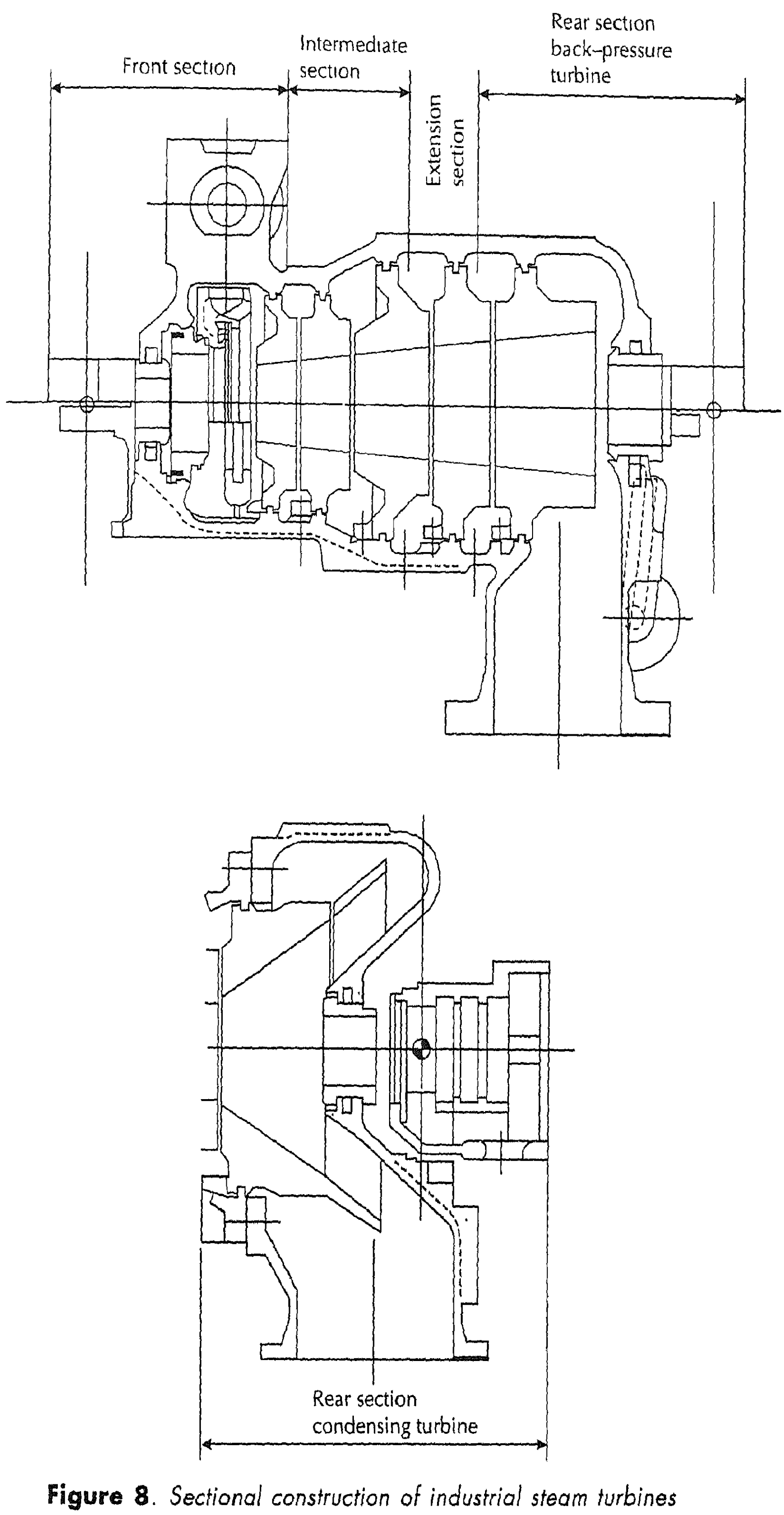


Figure 8. *Sectional construction of industrial steam turbines*

Conclusion

By careful choice of parameters and analysis of requirements, flows, and range of operations, it is possible to optimize any system configuration for making best use of the energy expended. In the endeavour, all the parties – the user, the system designer, and the equipment manufacturer – have, therefore, significant role.

Gas Turbines Burning Naphtha: Special Features

Satish Pandey,[1] K K Sharma, Avtar Singh, Rod Oglesby

Introduction

In India, rapid industrial development in the last decade and limited energy reserves have increased the quest for alternative cheaper fuels for power generation. Naphtha has been recognized as one of these alternative cheaper fuels for power generation in Indian industries using gas turbines. It is widely known that naphtha is cracked to produce ethylene or gasoline, which command premium prices in the market. This process, however, is used only in some of the advanced countries. In India, the requirement for cracked products has been limited. However, the availability of naphtha at low costs has rendered it highly suitable as a gas turbine fuel for power generation. Though there are a number of gas turbine installations using naphtha as fuel, these plants are normally in capacities of 10 MW plus, and, with a few exceptions, generally use naphtha as back-up fuel.

Special Features of Naphtha-burning Gas Turbines

In India, Triveni Engineering Works Ltd is supplying combined heat and power (CHP) plants of less than 10 MW capacity using gas turbines with naphtha as fuel. These turbines are manufactured by European Gas Turbines Ltd (EGT) UK – the GEC Alsthom Group, Triveni's collaborators. Some of the installations under execution by Triveni are designed to fire naphtha as the main fuel and high speed diesel (HSD)/kerosene as back-up fuels. This paper discusses features that are specially incorporated to ensure reliable and safe operations in a plant when using naphtha as fuel. The following systems/auxiliaries of gas turbines have received special consideration:

[1] The Triveni Engineering Works Ltd, P B No. 5848, 12-A, Peenya Industrial Area, Bangalore 560 058, India.

- the fuel forwarding and boosting system;
- the fuel distribution system;
- the ventilation with the fire and gas system;
- the drain and vent system; and
- the purge system

Fuel Forwarding and Boosting System

While designing the fuel system, the following two typical characteristics of naphtha have been taken into consideration:

- low flash point (less than 23 °C) and high vapour pressure; and
- low viscosity (less than 0.5 CST at 3 °C)

Low Flash Point and High Vapour Pressure

The above features make naphtha a highly volatile and inflammable liquid. The following safety precautions must, therefore, be taken into consideration

- During the start and stop sequences, there is the likelihood of some naphtha getting trapped in the pipeline resulting in vapour locking.
- Any naphtha vapour and air should be removed from the system pipes because the formation of a mixture of atmospheric air (oxygen) and naphtha is very explosive.
- Unburnt naphtha must be removed from the system when the gas turbine shuts down, and during abortive starts.

The above requirements necessitated extensive study and discussions with some of the users of naphtha-based CHP plants, and it was considered necessary to use HSD oil for start-up/stop sequences.

There is no gainsaying the fact that a gas turbine can be started and stopped on naphtha and it has already been tested in some of the existing gas turbine installations, where naphtha is being used as a back-up fuel. However, this practice is not entirely safe and the use of HSD is absolutely essential for the sake of safety.

Low Viscosity

Naphtha provides almost nil lubrication and is highly corrosive in nature resulting in excessive wear of high-pressure boosting pumps. Traditionally, Hitek is added to naphtha to provide lubrication to reduce pump wear. However, the use of Hitek is advisable only for systems where naphtha is used in frequently and as an alternative fuel. Further, the high cost of Hitek is a limiting factor concerning its use. In view of this, due care must be taken to ensure that fuel system components like pumps and valves are suitable for the very low viscosity fluid, with special emphasis on the type of seals which are more exposed to wear. While naphtha-forwarding pumps are low-pressure pumps, naphtha-boosting pumps are high-pressure pumps of the reciprocating type with their own separate lubricating oil system. These pumps conform to API 610 and are made of material which can handle a very low/nil viscosity liquid like naphtha.

Further, keeping users' observations and recommendations in view, the system is designed to blend one per cent HSD into the naphtha to ensure better functioning and long

pump life. In view of the already existing HSD circuit, this provides an economically-effective solution and avoids the use of Hitek.

Fuel Distribution System

While using naphtha, the moving components in the fuel system which require lubrication and maintenance need to be restricted. Two design approaches are available to design the fuel distribution system:

- the conventional mechanical flow division of fuel; and
- the pressure flow division.

The conventional mechanical flow division of fuel uses positive displacement gear pumps which pump the liquid fuel to the flow divider. The flow divider uses gear pumps driven by a single shaft It further pressurizes the fuel and directs it to each combustor. The number of gear pumps is equal to the number of combustors Studies conducted by leading gas turbine manufacturers indicate that a low lubricity fuel like naphtha reduces the life of the flow divider, which requires frequent maintenance/replacement. In view of this, with small gas turbines, a pressure flow division system is preferable and is easier to operate.

The gas turbines manufactured by EGT, UK, employ only one fuel-boosting pump, and further fuel distribution into the combustion chambers (can-annular type) is affected by the resistance offered by fuel nozzles. Further, each combustor is fitted with a duplex liquid fuel nozzle, which maintains high fuel line pressure even at the time of starting when only a small quantity of fuel is required. Figure 1 shows a typical fuel distribution system.

Ventilation with a Fire and Gas System

In European classification, naphtha falls under Group II A, while in the US, it is grouped in Class I, Group D, which also includes natural gas. The auto ignition temperature of natural gas is nearly 600 °C, whereas that of naphtha is 290 °C. Compared to natural gas, the flammable limits of naphtha in air are very low. Naphtha has a lower explosion limit of 0.9% and an upper limit of 6% by volume. The upper and lower explosion limits of natural gas are 3.8 and 17% respectively. In other words, natural gas has a wider flammable range, and, hence, needs to reach much higher concentrations before it becomes explosive. Naphtha, on the other hand, becomes explosive in very small concentrations, and, therefore, calls for an adequate ventilation system. The appropriate temperature classification for naphtha fuel as per specification IS: 5571-1979 is T3 which restricts maximum surface temperature to 200 °C. The accessories and gas turbine compartments would be classified as Class I Division II, Group D, as per NEC standards and Group II A, as per European classifications (EEC CENELEC EN 50014), which are the same as for natural gas.

As the classification for gas fuel and naphtha are the same, the enclosure ventilation design philosophy is common to both and the preferred reference is always the Institute

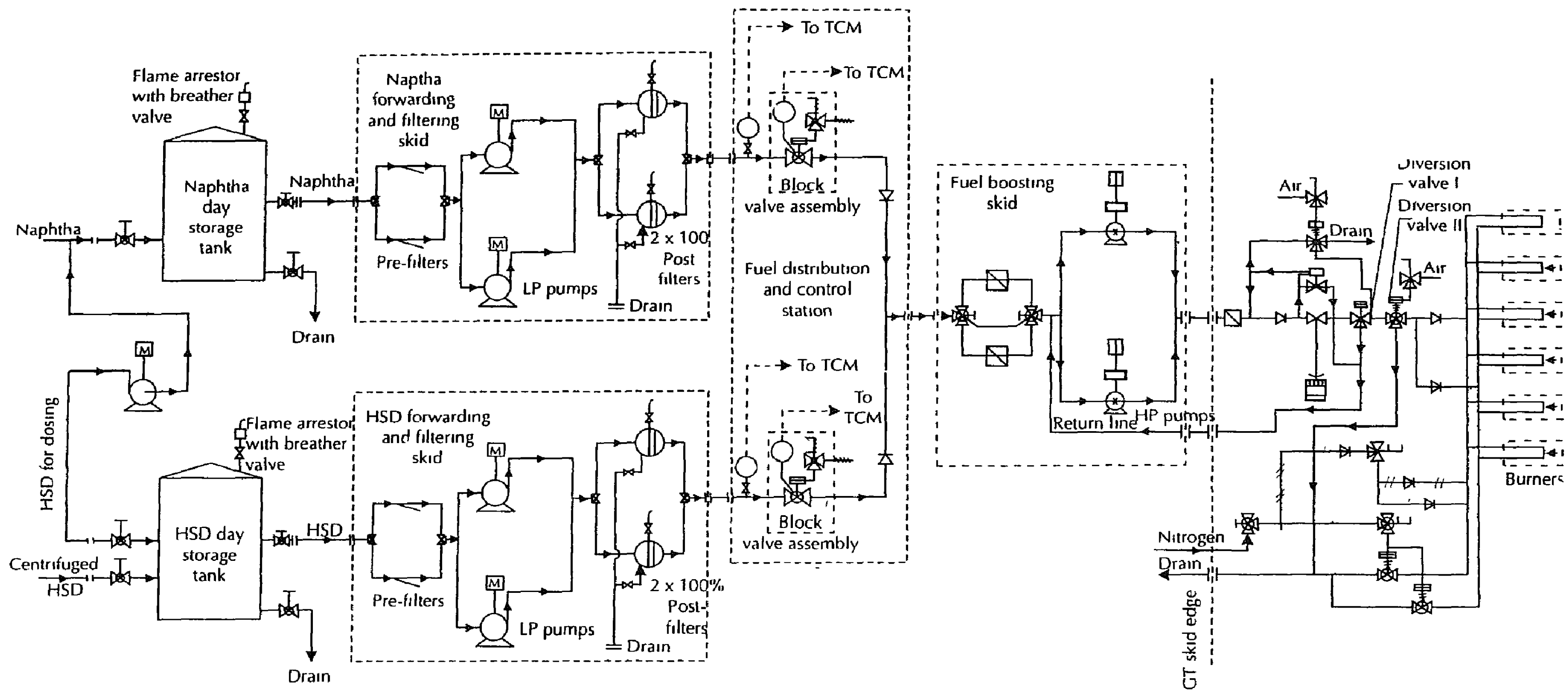


Figure 1 *A typical fuel distribution system*

of Petroleum (IP) Area Classification Code for Petroleum Installations (bearing part 15 of the IP model code of safe practice in the petroleum industry). Born out of the experience of many gas turbine installations, the IP codes now include sections specifically related to the layout of gas turbines.

While designing the ventilation gas turbine enclosure, certain factors have to be taken into account; whether the gas turbine enclosure is located in a safe or a hazardous area (normally enclosures are located in safe (non-hazardous) areas which is depressurized in relation to the area outside it); the underlying philosophy must always be that in the event of structural or any other failure the atmospheric air will flow from the safe to the hazardous area and not vice versa. While fire and gas system precautions similar to those in case that of natural gas are followed, emphasis is laid on the selection of suitable naphtha vapour detectors to sense the presence of the naphtha vapour even at concentrations of 0.9%.

Drain and Vent System

Owing to the highly flammable characteristics of naphtha, the following features are considered while designing, installing, and operating the vent and drain system in the gas turbine, which may contain naphtha either in the liquid or the vapour form.

Flammability

The sources of ignition which need to be considered in a naphtha-handling facility include the following:

- electrical sparks across gaps between current-carrying contacts or through static electricity discharge;
- fire from naked lights, careless smoking, hot repair work, exposed incandescent material, etc.;
- internal combustion engines, spark ignition systems, and hot spots on exhausts;
- spontaneous combustion – pyrophoric materials, leaks of hydrocarbons above spontaneous ignition temperature;
- frictional ignition – impact or rubbing when using power tools, or mechanical failure of rotating equipment; and
- high temperature surfaces – high temperature steam lines or other hot surfaces whose temperature exceeds the spontaneous ignition temperature.

Toxicity

The principle hazard in the storage and handling of naphtha 'is' the flammability, but it must be noted that a concentration of two per cent in the air is likely to cause death rapidly.

Naphtha, being an aromatic hydrocarbon, can be readily absorbed into the body by inhalation and by absorption through the skin. Aromatic hydrocarbons cause local defatting and irritation of the skin and this may lead to blistering and dermatitis. Appropriate precautions must, therefore, be taken in handling the material, and in maintaining

pumps, tanks, valves, etc. It is recommended that appropriate clothing, i.e., gloves, overalls, etc., be worn during these activities.

Electrical and Sparking Hazards

- All electrical equipment used in the vicinity should be of flame-proof, i.e., with a minimum rating of Zone II.
- Maintenance tools (i.e., hammers, wrenches, etc.) should be so designed so as not to generate sparks when in use.
- Earthed conductive pipes should be installed, and bonded between flanges.
- Any free water which is present should be regularly drained from the tankage.
- The drain tank shells should be earthed. Often the floating cover in a fixed roof tank is of polyurethane construction (of low conductivity). It is essential that all metal attachments to this cover are connected to the shell by flexible bonding straps. The resistance to earth from any point on the cover should not exceed 10 ohms.
- Clothing can increase electrostatic potential to such extent that an incendiary spark may get discharged to an earthed conductor. Anti-static shoes should be worn, but it should be appreciated that these could be ineffective if the wearer were walking on a material with low conductivity.
- High velocity steam cleaning should be avoided even when the nozzle is earthed. Tank cleaning is permitted with high pressure water jets only – after gas freeing or inerting.

Valves

Ball valves are preferred and should be anti-static and fire-proof, with a stainless steel body and trim with glass reinforced Teflon seats and seals. An electric earthing strap is required between the steam and the body.

Naphtha Vapour Hazards

As naphtha vapour is heavier than air, any leakage of fuel from flange joints, connections, etc., will generate vapours which will tend to accumulate at low points. Hence, measures must be taken to remove this vapour or eliminate low points. Pipes, for instance, should be either run above ground level or in sand-filled trenches. Any low points which cannot be eliminated should be equipped with devices to draw off the vapour to a safe area where it can be flared off at a low level. Normally, a vapour extractor is provided close to the base of the gas turbine which draws naphtha vapour from inside the base frame in case of leakage. This vapour is collected at the bottom. All the naphtha drains out from individual equipment drains and is conveyed to a safe distance to be terminated or routed back to the day storage tank.

Auto Drain Valve

While vents and drains as required on the basis of the above considerations are provided, an additional drain is provided in the exhaust ducting to remove any liquid fuel which collects in the exhaust ducting after an aborted start. For this purpose, an auto drain valve is provided, which is operated by air from the delivery stage of the gas gen-

eratôr. The valve remains closed when the turbine is running and is opened for drainage when the turbine is stopped.

Purge System

The use of naphtha as fuel calls for special purging requirements such as:

- purging with HSD during start and stop; and
- purging with nitrogen after shutdown

Purging with HSD

The purge system is illustrated in Figure 1. When a start sequence is initiated using one of the soft keys on the control panel, the HSD fuel-forwarding pump (low-pressure pump) receives a start permissive. On the availability of HSD at a predetermined pressure, the block valve opens and passes the signal for the starting of the high-pressure boosting pump along with the closing of the liquid fuel drain valves, thereby filling the liquid fuel spill line. The system then moves through the sequence listed below.

1. Diversion Valve I opens.
2. Throttle valve opens to permit a small amount of HSD (approximately 10 litres per minute) to flow through the system for a present time.
3. Diversion Valve I closes.
4. The drain valves open and drain the system.
5. A signal is passed to the low- and high-pressure fuel pumps to stop diesel supply.
6. Throttle valve returns to closed position.

Purging with Nitrogen

HSD purging is done only up to Diversion Valve II. However, after the stop sequence, it is necessary to remove any unburnt liquid fuel from the combustors. Normally, the standard practice is to use compressed air for evacuation of any liquid fuel/HSD or its vapour. It is not safe, however, to use air with naphtha fuel as it may quickly produce a mixture of oxygen and naphtha vapours in a hot atmosphere, which is very explosive. Owing to the above consideration, it is a safer practice to use an inert gas like nitrogen for purging the combustors.

Conclusion

In brief, once a gas turbine is designed to operate on naphtha fuel, special care needs to be taken while using it. While handling naphtha in a gas turbine is dangerous if adequate precautions are not taken, it is otherwise quite user-friendly if safety procedures are adhered to. This paper considers only the system configuration and details for a gas turbine operating on liquid fuel only. The philosophy and system details could be different for a bifuel/dual gas turbine system, or when naphtha is considered as a back-up fuel.

Innovative Cogeneration Schemes for Fertilizer and Process Plants and Refineries

S Krishnan,[1] A S Belagali

Introduction

Cogeneration is usually the most economical way of producing electric power as well as heat for process plants. The Indian industry is increasingly looking towards captive power generation for uninterrupted and reliable supply. This, coupled with significant heat requirements, often as steam, has created an added emphasis for cogeneration schemes.

The steam and power requirements of each industry are unique. Careful considerations are to be given to the quantity as well as quality ot steam along with the power requirements while engineering the system. The parameters to be taken into account, while evolving the cogeneration scheme for specific applications, are discussed, and the design features that are to be incorporated for optimal and reliable performance are elucidated.

The discussions are supported by three case studies. The first deals with a gas turbine based cogeneration system for a fertilizer plant, where unique design features have been incorporated to ensure constant high quality steam supply under different operating requirements. In the second case, the cogeneration scheme for a refinery plant based on unusual and difficult fuels is illustrated. The last case describes how the necessities of a chemical process are addressed to arrive at optimum configuration.

Finally, some of the special analysis techniques required to be developed or the design and supply of systems for such diverse applications are also dealt with.

The power sector is assuming more and more importance in the Indian scenario. The captive and cogeneration concepts are, especially, becoming more innovative in arriving at cost-effective solutions to steam and power needs. This makes it desirable to share

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the design experience across the industry in order to increase the general awareness of the existing capabilities and limitations. This would increase the total knowledge available in the industry, in addition to providing help in the assessment of what is possible. This paper is an attempt to share our experience in the area of combined-cycle cogeneration plants.

For the design of a cogeneration plant and the various unit equipment in it, today's designer can make use of a host of design techniques and a variety of softwares. Yet, given the vast spectrum of design possibilities, the virtue of a design depends mainly upon the expertise of the designer. This expertise is largely enriched through his experience with similar plants. One more reason for the importance of this experience is that each situation is unique in respect of its demand and design parameters, and the designer has to concentrate on those aspects much more than the general aspects in order to achieve a good design. It is also possible to capitalize on the unique features of the situation to achieve a very economical design.

This paper discusses various aspects involved in the design of a cogeneration process based mainly on the particular demands and parameters of the system, as opposed to the general demands. Therefore, innovative deviations from the conventional designs are emphasized. This paper presents three case studies highlighting design considerations vastly different from each other, which are indicated by the unique demands of the processes.

Design Considerations

The design of a cogeneration plant may involve many aspects, which cannot be provided by one type of tool. The use of multiple tools for analysing the key aspects in the cogeneration plant allows the designer to improve his visualization of the plant a *priori*, and thus assists him in making a proper assessment of various design choices and innovating the conventional designs. This section discusses the different design considerations.

The Process Requirements

The process steam requirement at the battery point and the power requirement are factors which influence the sizing of various equipment. Different combinations of steam and power requirements may be required at different points of time, resulting in a steam power envelope within which the satisfactory operation of the plant is expected. The designer should also know the weightage given to each of these requirements. Using these specifications, the skeleton design and sizing of the unit equipment are arrived at through the heat and mass balance.

System Performance at Design Conditions

This step represents the macro scale analysis of the system at the design point. At design conditions, the system should satisfy all the constraints imposed upon it by the process metallurgical, and safety requirements and corrosion prevention. While satisfying these constraints, the system should be optimally sized at the design conditions. Special-purpose steady-state flowsheet simulators are usually used for this purpose.

System Performance under Extreme Conditions

This is a macro scale analysis and extreme conditions of operation are expected to occur. The system constraints mentioned above should be satisfied under these conditions too. Also, the system should not show unacceptable performance deterioration.

Dynamic Response

The system start-up and shutdown operation is best analysed with the aid of its dynamic simulation. The start-up or shutdown of equipment in the various units of the system in synchronization with others is imperative. For example, the gas turbines can be started up very fast, but the heat recovery steam generator (HRSG) has more thermal inertia. Even if it were designed for less thermal inertia, the pressure gradients in the steam drum change quite fast, resulting in large thermal stress which implies fatigue. Also, the control system design and performance analysis can be done with the dynamic analysis. For example, during HRSG start-up, the most crucial aspects are monitoring the drum levels due to the swell effect when the liquid water in the tubes is expelled by the first vapour phase formed, and monitoring the pressure gradients in the steam drum.

Dynamic simulation is not as straightforward as steady state simulation, and the model validity should be ascertained for the entire range of plant operations. Very often, good tools for dynamic simulation are not available or accessible, and the designer is forced to rely heavily on his past experience to visualize the dynamic response of the system.

System Operation

In this step, it is ensured that the system operation is as desired. Various issues considered at this stage include:

- the start-up process;
- the shutdown process;
- system maintenance;
- accessibilities of individual components;
- manual over-ride over the control system; and
- by-pass lines, valves, and damper provisions.

Fluid Flow Analysis

The geometry of the exchanger is very important to the uniform distribution of the fluid flow. More often than not, the sudden curves, bends, or impediments in the fluid flow path result in fluid flow distribution which is very different from what was expected. The maldistribution of the flow of fluid outside heat transfer tubes or in the gas flow near the burners in an HRSG cause a substantial drop in the performance of the corresponding equipment. This affects the overall plant in general. The detection of this maldistribution is possible through fluid flow analysis by finite element techniques carried out at key locations in the plant. The gas velocity vectors in the inlet zone of an assisted circulation type HRSG are shown in Figure 1.

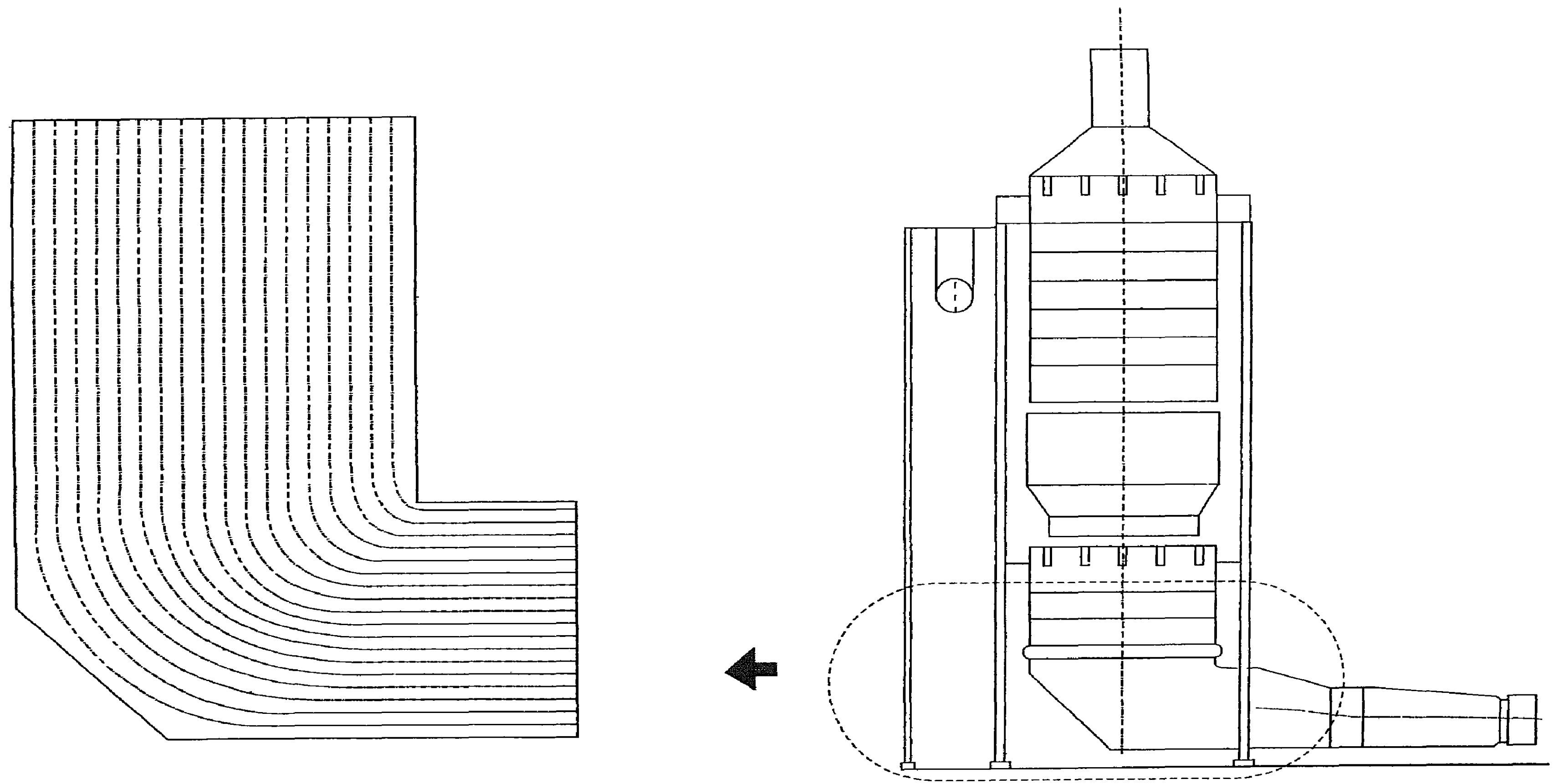


Figure 1. *Gas velocity vectors at the inlet of an HRSG determined by a finite element software*

The design considerations discussed above give rise to a number of innovations in the plant design. These innovations may vary from case to case. To strengthen this point, three case studies are discussed below, which are representative of different industries where cogeneration plants were installed. One would appreciate that the design requirements and constraints are very different for each industry, and have given rise to entirely different perspectives to the evolution of the design.

Case Study 1: a Fertilizer Plant

The first case study presents the case of a fertilizer plant that employs a cogeneration unit. There are two gas turbines connected to separate HRSG units having supplementary fuel firing. The high-pressure process steam requirement is critical for all compressor drives. Therefore, apart from these HRSG units, a service boiler is also provided.

A unique need of this plant is the wide variation in the power and steam demands. The plant is required to deliver any combination of high/low power and high/low flowrate of process steam of desired specifications. This poses a challenge from the control system design point of view. This problem can be best addressed by having two fuel firings in an HRSG unit, as opposed to one. The amount of fuel fired closer to the steam exit is controlled by the steam temperature requirements, whereas the amount of fuel fired at an intermediate location in the HRSG is controlled by the steam flow requirements. Apart from meeting any metallurgical concern, this arrangement provides the effective control of the steam flowrate and quality. Good control over steam quality eliminates the need of attemperation, which implies good thermal efficiency and good quality of steam. However, this modification results in the increase in the size of the boiler due to a decrease in the temperature differential in the hot and cold streams. On the other hand, lower temperature differentials also mean smaller energy losses.

One more speciality of design in this power plant is the elimination of the gas by-pass system. For this reason, the HRSG is required to have a quick start-up to match that of the gas turbine. This means that the complete power plant starts up quite fast without losing energy through the by-pass stack. In addition, maintenance is greatly reduced for this scheme because of the elimination of moving parts in the diverter dampers.

Assisted circulation-type boilers have been used here. These boilers employ small diameter tubes in which it is easier to achieve the desired flow pattern. The recirculation ratios are also small in this type of equipment, which decreases the pump and piping costs considerably.

Case Study 2: a Petrochemical Plant

This case study is being presented to demonstrate the application of heavy viscous oils as fuel in the boiler. In a typical refinery, these oils are available from other process units and a great saving on the fuel cost can be achieved if they can be fired in the boiler and used for the production of steam. Again, the various oils are not to be mixed with each other due to their chemistry or high viscosities. The usage of such bad fuels is always a difficult problem. In this particular plant under study, four such fuels are used. In addition to them, a fifth fuel, light diesel oil (LDO), is used during start-up.

When a switch-over from one fuel to another fuel is intended, to avoid their mixing, the boiler is operated on LDO for some time after one fuel, and before the next. Thus, LDO acts also as a switch-over fuel. While LDO can be atomized in air owing to its low atomization temperature, the other four fuels can be atomized only by steam. This necessitates a complicated burner design. Hot steam flows in the innermost tubular region in the burner and the fuel oil flows in the annular region surrounding it. The oil gets atomized through small holes at the specially designed tip of the burner before getting ignited.

Since there is a considerable difference in the viscosities of LDO and other fuels, the diameter of holes at the burner tips or nozzles for atomizing the LDO stream is smaller than that for other fuels. Therefore, at the time of switch-over from some other fuel to LDO or vice versa, the burners have to be shut off and taken out for changing the nozzles.

Another aspect is the high vanadium content in these bad fuels, which leads to hot corrosion at temperatures above 550 °C. The hot corrosion is due to the deposition of vanadate compounds which have a melting point in this temperature range. To take care of this problem, an adequate quantity of MgO powder is added to the fuel in a stirred tank vessel before it reaches the burners. This leads to the formation of vanadates which have very high melting points, thus avoiding hot corrosion.

To increase the thermal efficiency of the boiler, the air is preheated by the exhaust flue gas after the economizer in an air preheater. Where the tube wall temperature in the air preheater becomes lower than the dew point of the flue gas, condensation of flue gas compounds on the tube surface leads to cold corrosion. To take care of this problem, the air is heated by steam in another heat exchanger before it enters the preheater so that the tube wall temperature is always maintained above the dew point of the flue gas.

Case Study 3: a Process Plant

This case study relates to a chemical plant where a combined-cycle cogeneration module has been put up in order to satisfy the requirements of process steam as well as the generation of power. The system had to be designed for two situations – open cycle operation of gas turbine and the complete combined-cycle plant operation.

The former mode had to be considered essentially for the first year of plant operation when the steam turbine would not be in service. Diverter dampers are used to divert the gas flow to a bypass stack and to isolate the HRSG.

There are two gas turbines, each connected to one dual pressure HRSG unit. This arrangement ensures that the steam is available to the process even when one HRSG is not operational. The heat available in the gas is quite high compared to the requirement of the process steam, thereby making the option of additional power generation in the steam turbine attractive. The high heat content in the gas also means that supplementary firing is not required in the HRSG.

The process requirement is for low pressure (LP) steam. The HRSG is designed to generate high pressure (HP) steam of desired specifications and LP steam of intermediate specifications. The HP steam is used for generating power in the steam turbine. A large part of the intermediate pressure (IP) steam is used in the deaerator and surplus steam is mixed with the turbine extraction steam to be used as process steam. Steam genera-

tion in the HP circuit depends upon the sliding pressure of the HRSG steam turbine system. The mixing of the turbine extraction LP steam and the IP steam is found to be a better alternative to generating LP steam as per the requirements of the process.

Though the HRSG steam turbine system operates under the sliding pressure mode, the steam pressure is regulated so that it does not fall below a certain level. This ensures the satisfactory operation of the HRSG.

The HRSG design ensures that the attemperation of the superheated steam in the boiler is very low at design load. Higher attemperation implies higher loss in the thermal efficiency of the boiler as well as less quality of the steam since water is directly added to it. At the same time, a small amount of attemperation is useful for a tight control over the boiler outlet steam superheat. This small quantity of attemperation is provided between two superheater coils which is a better option than providing attemperation only after both the coils because of higher thermal efficiency.

Conclusion

The design of a cogeneration plant needs expertise based mainly upon the experience of the designer. The complete design procedure involves various considerations including sizing, steady state and dynamic simulations, system operability, and fluid flow behaviour. Each of these requires the appropriate application of multiple design tools. The innovations that could be carried out based on the particular needs of the industry have been illustrated with the help of three case studies taken from three different industries. The case studies highlight the diverse needs of different industries, and their influence on the plant design.

High Pressure Boilers Using Fossil Fuels for Cogeneration

R Kamaraj,[1] T Balakrishnan, S Shanmugam

Introduction

Cogeneration in India has, in the past, been restricted to meeting the on-site heat demands of the process and generation of electrical energy for captive consumption, thus reducing dependence on the grid supply in sugar, rice, paper, and textile mills, chemical and fertilizer factories, petrochemical and steel industries, etc. More recently, in order to meet the increasing power demand, and with a view to efficiently utilizing the available power generating potential, the Government of India is encouraging industries engaged in cogeneration to export surplus power to the grid. This has led to increased demand for boilers with higher capacity, higher steam pressures, and higher temperatures.

BHEL's Capability

BHEL is engaged in the design, manufacture, supply, installation, and servicing of boilers of numerous specifications for utility and industrial applications. Process industries employing cogeneration are in need of boilers with widely varying capacities, pressures, and temperatures, using locally available fuels. BHEL, with its wide range of boiler designs, has met the varying cogeneration needs of industries on a large scale. During the last 30 years of its existence, it has supplied more than 250 boilers to various industries for cogeneration to meet captive and process needs. The boilers are designed to burn a variety of fuels – fossil fuels such as coal, oil and gas; and industrial by-product process waste gases such as carbon monoxide, blast furnace gas, coke oven gas; etc.

BHEL has the capability to engineer and supply a wide range of boilers tailored to meet the requirements of cogeneration industries, such as unit capacity, fuel characteristics, space requirement, etc. (Table 1).

[1] Bharat Heavy Electricals Ltd (BHEL), BHEL House, Siri Fort, New Delhi - 110 049, India.

Table 1

Range of available BHEL boilers

Boiler type	Maximum steam generation capacity (tonnes/hour)	Fuel type
Package Boilers (VP)	180	Oil/gas
VU60	360	Oil/gas
VU40	500	Coal, oil, gas
VU40S	125	Coal, bagasse, wood
VU60S	80	Coal, bagasse, wood

The above boilers are bidrum boilers suitable for steam parameters of 110 kg/cm^2 and 540 °C (except stoker-fired units). Single-drum boiler designs will be adopted to achieve still higher pressures.

Salient Features of BHEL Boilers

The boilers fabricated and supplied by BHEL have the following features:

- fully welded waterwall construction;
- seamless steel tubes for waterwalls, superheaters, boiler banks, and economizers;
- special corrosion-resistant materials for air heaters and gas ducts;
- modular boiler design resulting in shorter erection time;
- stringent quality control both at shop and site; and
- excellent after-sales service.

Special Design Features of Cogeneration Boilers

Cogeneration demands that the boilers be suitable for widely varying operating conditions. BHEL boilers have in-built features for meeting these duty conditions. Some of these features are listed below.

- *Wide range of temperature control (large boiler turn-down).* A prime requirement of a cogeneration plant is the ability to generate steam with rated steam temperatures over a wide load, which the BHEL boilers are designed to supply in some cases even down to 25%.
- *Multi-fuel firing.* With their suitability for firing a variety of fuels, either independently or in combination, BHEL boilers offer maximum flexibility in the use of industrial by-products. Most of the BHEL units are designed for firing multi-fuels like coal, oil, and/or process gases such as blast furnace gas, coke oven gas, etc., either in combination or singly.
- *Minimum emissions.* The firing system burners are designed for minimum emissions of combustion pollutants like oxides of nitrogen, carbon monoxide, etc.

- *Withstand load fluctuation.* These boilers have the capability to meet wide fluctuations in steam demand, as the bidrum boilers with large boiler banks and a substantial water holding capacity are capable of meeting load fluctuations with ease.
- *Imported steam superheating.* Superheating of steam imported from other sources at different temperature levels is unique to process industries. To meet such requirements, BHEL can offer boilers designed with dedicated superheaters to superheat the import steam. An alternative can be designed to facilitate the superheating of a mixture of import steam and generated steam to the rated temperature.
- *Export steam from boiler.* Some industries need high-pressure saturated steam in addition to superheated steam. To meet this requirement, the boiler can be designed to supply saturated steam from the steam drum.
- *High steam quality.* Efficient drum internals ensure high steam quality as demanded by a critical process and a steam turbine.
- *Steam heater attemperation.* Steam purity is an important parameter which affects the process as well as operation of the steam turbine. The control of steam temperature by spraying feedwater is a normal practice. However, if the feedwater quality is poor, then mixing the feedwater with steam directly affects the steam purity. Under these circumstances, saturated steam tapped from the drum is condensed and used for spraying. Another method is the cooling of superheated steam by the non-mixing type surface attemperator, thereby avoiding contamination by mixing with feedwater.
- *Feedwater heating.* While designing the unit for different fuels (say coal and oil), feedwater temperature entering the economizer has a bearing on the corrosion in economizer coils. However, raising the feedwater temperature to the higher level demanded by the worst fuel may not always be economical, as high feedwater temperatures affect the heat transfer in the economizer while firing the other fuel also. By providing the drum coil heater in the boiler circuit (i.e., a separate feedwater heating coil installed in the drum) to heat the incoming feedwater before it enters the economizer, the feedwater temperature can be varied to the desired level depending on the fuel being used.
- *Pollution control.* The BHEL boiler systems are fitted with efficient dust-collecting equipment – an electrostatic precipitator – with a sophisticated control mechanism to reduce the emission levels to meet stringent pollution control requirements. BHEL has designed and supplied a dust-collecting system with an emission level as low as 50 mg per normal cubic metre.
- *Smooth and safe operation.* The boilers also have controls and instrumentation to ensure smooth and safe operations.
- *Provision for quick start-up.* Most of the process industries employing cogeneration need an uninterrupted steam supply. In case the operating boiler faces any difficulty in generation, the stand-by boiler has to come into operation without delay. To meet such an emergency condition, BHEL has designed a hot stand-by system which brings the stand-by boiler to the full rating in the shortest possible time.

Recent Trends in Cogeneration

The sugar industry is one of the major industries with substantial potential for cogeneration. An assessment made by a committee constituted by the Government of India indi-

cates that there is a potential for generating surplus power to the tune of 3500 MW in this sector alone. In recent times, due to the encouragement and incentives offered by the Government of India for captive power generation, the sugar industry is planning to go in for cogeneration employing high-pressure steam cycles in a big way. BHEL has risen to the occasion and has met the cogeneration requirement of the sugar industry by currently producing bagasse/lignite-fired boilers of 70 tonnes/hour generating capacity at 65 kg/cm^2 (g), and 485°C.

Fluidized Bed Combustion Boilers

During the past two decades, fluidized bed combustion (FBC) boilers, with their advantages, are emerging as an alternative to the boilers for steam generation based on other technologies. BHEL began investigating various aspects of the FBC process in the mid-70 and has become one of the technological leaders among the manufacturers of FBC boilers.

BHEL has a collaboration agreement with Lurgi Lentjes Babcock, Germany, for circulating FBC boilers. A 175 tonne/hour, circulating FBC boiler (CFBC) firing high ash coal is being supplied to a paper mill. 2 × 125 MW CFBC boilers burning lignite are under execution. BHEL offers CFBC boilers for utilities and industries.

Waste Heat Recovery Boilers

Cogeneration in petrochemical and oil refineries normally involves the use of either oil or a mixture of hydrocarbon gases, or two fuels, due to their availability. However, the rising cost of these prime fuels has led to a greater emphasis on higher overall cycle efficiency, maximum heat recovery, shorter payback periods, and lower capital costs, etc. In this context gas/liquid fuel-based cogeneration systems are now gaining importance and wider acceptance.

Waste heat recovery boilers play a very important role in combined-cycle cogeneration plants by recovering the sensible heat of exhaust gases from gas turbine, diesel engine, and sponge iron plants. BHEL, till date, has supplied more than 70 such waste heat recovery boilers to various industries.

Conclusion

The requirement of boilers for cogeneration applications for each particular process industry is unique due to its specific requirement. The various design aspects and functional/operational feasibilities of BHEL boilers offer various alternatives for different industries. Today, BHEL boilers are well established and are capable of meeting cogeneration requirements using all available fossil, biomass, and waste fuels.

The Tempest

John Bowen, R W Oglesby[1]

Introduction

The Tempest is a small-size gas turbine. It can generate 7.49 MW_e of electrical power to suit a wide range of utility and industrial power generation applications, including platforms, petrochemical facilities, paper mills, hospitals, chemical plants, and other cogeneration applications as well.

A lot similar to the Typhoon but scaled to achieve a higher power output, the Tempest complements EGT's, existing family of industrial gas turbines which includes the Typhoon and the Tornado, both of which are available in single- or twin-shaft configurations. These gas turbines have set standards throughout the industry for efficiency, reliability, and availability. Building on this and their demonstrated reliability, the Tempest incorporates technological advances in materials development and in manufacturing processes to deliver increased power and efficiency.

Representing design, engineering, and manufacturing expertise in a compact, easy-to-install package, the Tempest's key features include:

- 33% simple-cycle efficiency;
- excellent steam raising capability;
- emissions control by dry or wet techniques;
- power enhancement by steam injection;
- dual fuel and bifuel capability;
- cold-end drive;
- high availability;
- on-site maintainability;
- compact package arrangement; and
- self-diagnostic microprocessor-based controls.

[1] European Gas Turbines (EGT) Ltd, UK, C/o Triveni Engineering Works Ltd, P B No. 5848, 12-A, Peenya Industrial Area, Bangalore - 560 058, India.

Compressor Rotor

The 10-stage compressor is a scaled version of the highly efficient Typhoon single-shaft machine and has a 14:1 compression ratio and a rotational speed of 13 907 rpm. The compressor incorporates variable inlet guide vanes and the first three rows of stator blades for surge control during start-up.

The compressor turbine is a two-stage overhung design comprising high- and low-pressure stages. Both turbine stages feature stators of advanced dihedral design resulting in optimized stage efficiency. The high pressure turbine blades are investment cast and incorporate a corrosion and oxidation resistant coating. The blades incorporate a dual, triple-pass cooling technology, providing thorough and efficient blade cooling. The first and second stage discs are cooled by air bled from the compressor, but the low-pressure, second-stage blading requires no cooling.

Combustion

The combustion system incorporates six reverse flow tubular combustion chambers positioned around the high-pressure compressor casing. The Tempest also comprises a combustion system suitable for operating on natural gas or distillate fuel and is available with an automatic change-over from primary to secondary fuel at any load. Reduced exhaust emissions are achieved by using a dry low emissions (DLE) combustion system. Alternatively, conventional combustors, configured for steam or water injection, are available for NO_x reduction or power enhancement. A variable bifuel option allows the Tempest to run on two fuels simultaneously.

Bearings

The compressor spool is supported and positioned by tilt pad journal and thrust bearings, which offer exceptional stability and a long operating life.

Gearbox

An epicyclic type gearbox bolts directly onto the underbase and forms an integral interface and support to the engine core. Servicing is easily achieved by the removal of the top half of the gearbox casing. Output speeds of 1500 and 1800 rpm are available to suit 50 and 60 Hz operation.

Lubrication

The standard lubricating oil system is designed to supply oil to the engine, the gearbox, and the generator. Filtered mineral oil is supplied from the reservoir, which forms an integral part of the underbase, by a gearbox-driven main oil pump. The oil is cooled either by a water-cooled oil cooler mounted on the package or an air blast oil cooler mounted off the package. Oil temperature is controlled by means of a thermostatic

valve. An AC motor-driven pump provides prestart and post-shutdown lubrication. In the event of AC failure, a DC motor-driven emergency pump supplies oil to the hot bearings and provides a safe shutdown.

Starting System

The standard starting system uses an AC motor driven hydraulic pump that provides high-pressure oil to the hydraulic start motor. This rotates the turbine through a self-synchronizing clutch which is mounted on the main gearbox.

Compressor Cleaning

To minimize performance degradation due to compressor fouling, the Tempest incorporates a compressor hot wash cleaning system which can be used when the engine is running on-load. A cold crank wash facility is available when the engine is shutdown.

Controls

A fully integrated controls package, designed and manufactured by the EGT Controls Centre, provides automatic starting, running, and shutdown facilities, speed control, temperature monitoring, fault monitoring, and annunciation. Operator information and fault indication are displayed on a high resolution colour screen. The access to operator information is by way of front panel push buttons or a keyboard and trackerball. The display system features an on-line 500-message sequence of events recorder and an on-line trending facility for analogue and digital values, with a short-term trending of all mimic variables. The system can be expanded to include control of associated equipment.

Package

The Tempest is available as a packaged power plant for utility and industrial power generation applications. The driver package incorporates the gas turbine, a gearbox, and all systems mounted on a single underbase. For cogeneration applications the generator is mounted on a separate underbase. Oil and gas applications will have a single-piece underbase with either a multi-point or a three-point mounting for onshore or offshore use as required.

The lubricating oil reservoir is located beneath the gearbox at the drive-end of the package and the lubricating and start system components are mounted on the tank top and are easily accessible using the maintenance lifting frame provided. The gas fuel system and the liquid fuel valve are mounted within the underbase beneath the engine. The liquid fuel pump and filters are mounted on the lubricating oil tank top ensuring easy access for maintenance.

The intake and exhaust silencing equipment and associated ducting is designed to suit all configurations and is available in carbon steel for onshore/inland sites or stainless steel for offshore/coastal environments. For noise reduction, a painted carbon

steel acoustic enclosure is available which is mounted on the underbase. This encloses the engine, the gearbox, and the fluids systems and reduces noise levels to 85 dB(A) at 1 m from the enclosure and 1.2 m above ground level, under free field conditions. The enclosure incorporates suitable doors and hinged lift-off panels which provide access for servicing. For offshore or coastal installations, a stainless steel enclosure is available as an option.

Weight and Dimensions

The schematic diagrams, weights, and dimensions listed below are for typical standard equipment.

1. Weight (generator set): 55 000 kg (121 253 lb)
2. Dimensions

   - Overall length driver package: 6.5 m (256")
   - Overall length generator set: 9.79 m (385")
   - Width: 2.4 m (94")
   - Height to the top of the enclosure: 3.49 m (134")

Maintenance and Service

The Tempest incorporates a number of features that facilitate on-site maintenance and minimize operational downtime. These features are listed below.

- Vertically and horizontally split intake casing which allows easy access to the air intake.
- Multiple borescope inspection ports which permit thorough condition monitoring without gas turbine disassembling.
- Horizontally split compressor casing which enables detailed inspection of the compressor rotor and stator blade.
- Quick change out of the compact core which requires no alignment checks.
- Combustion chambers, flame tubes, and ignitors which are easily accessible for inspection without the removal of the main engine casing.

The Tempest has planned service intervals of 8000 fired hours, or annually, which are designed to fit in with plant maintenance schedules. A major inspection is scheduled every three years or after 240 000 fired hours.

Customer Support Services

EGT has a dedicated world-wide customer support network, which comprises a range of services covering technical and practical support, training, and itemized spares distribution.

Conclusion

Offering a range of features such as steam injection on biofuels, the Tempest provides a stable frequency and electricity supply which makes it attractive as a prime mover for use in the cogen industry.

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Cogeneration in India Utilizing Bagasse and Lignite as Fuel

Anand H Mokashi[1]

Introduction

In India, bagasse has been conventionally used as boiler fuel to generate steam for driving turbines in mills and power houses; the exhaust being used for process equipment. The trend is now in favour of cogeneration, wherein factories generate power to meet their own requirement and offer the surplus electricity to the power grid. The state governments, and the Government of India as well, are also giving a lot of importance to cogeneration activities.

The concept of combined heat and power generation has come of age in the Indian sugar industry, where utilization of bagasse as a renewable, non-polluting, by-product fuel is indeed ideal for such a scheme. The overall potential of cogeneration is placed at 10 700 MW in the country, and at over 3500 MW in the sugar sector, which appears reasonable. The experience in India, though modest in scale so far, has been encouraging, and cogeneration is being looked upon as an economically attractive option by the sugar industry. As a result, more and more sugar factories are opting for high-pressure boilers so that power cán be generated with lower steam consumption. Sugar factories are generally season-oriented and run for only six to seven months. The boilers remain idle for the rest of the year. With cogeneration, however, power can be generated with other waste fuels and can be offered to the grid. Since bagasse is not available after the crushing season, more developments towards the identification of alternatives to bagasse are being made.

The Thiru Arooran Sugar Factory (TASF) in Tamil Nadu has installed a high-pressure boiler of 66 kg/cm^2 outlet at a temperature of 485 °C. It is the first boiler in India using such high pressure technology for burning bagasse in a sugar factory. For the period after the crushing season is over, TASF proposes to use lignite to generate power as this fuel is available from the nearby Neyvelli Lignite mines. Thus, this is the first boiler of its

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kind burning bagasse as well as lignite as alternate fuel to generate steam. The technical specifications of the boiler are summarized below.

1. Main fuels: bagasse and lignite
2. Fuel Analysis
3. Ultimate Analysis

	Bagasse	Lignite
H_2 (%)	3.25	1.49
C (%)	23.5	25.78
N_2 (%)	—	0.3
O_2 (%)	21.75	15.58
Moisture (%)	50	50
Ash (%)	1.5	6.3
S (%)	—	0.55
GCV (kcal/kg)	2272	2750

4 Utilities: boiler feed-water

	Before Treatment	After Treatment
TDS (max.) (ppm)	1000	0.10
Oxygen (max.) (ppm)	0.007	0.007
Suspended solids ppm	—	—
Silica (SiO_2) (max.) (ppm)	9	0.02
Iron (max.) (ppm)	0.01	0.01
Copper (max.) (ppm)	0.005	0.005
pH	10.8–11.2	8.5–9.0
Specific conductivity at 25 °C us/cm	1111	0.20
Residual phosphates (max.) (ppm)	30.0	—
Condensate		
Quality		Pure
Hardness		Nil
pH		8.5–9.0
Temperature		85 °C

5. Boiler design parameters

- Capacity – maximum continuous rating (MCR) (t/h): 70; and peak rating for half an hour in eight hours (t/h): 77.
- Pressure – steam pressure at main steam stop valve outlet [kg/cm^2(g)]: 66; and design pressure [kg/cm^2(g)]: 77.5.
- Temperature – steam temperature at superheater outlet at MCR (°C): 485 ± 5; flue gas temperature leaving air preheater at MCR (°C): 160; feed-water temperature at deaerator inlet (°C): 85; feed-water temperature at economizer inlet (deaerated)

(°C): 105; steam control range (% MCR): 60–100; and efficiency (%) MCR – bagasse 69 ± 1.5; lignite 75 ± 1.5.

The bagasse-cum-lignite-fired boiler at TASF in Tamil Nadu has been supplied by TBW, and has the following facts to its credit. It is the first boiler in India:

- which would use bagasse and lignite;
- with a 70 tonne capacity, with a peak of 77 tonnes/hour on bagasse-cum-lignite with independent peak generation;
- with 66 kg/cm^2 superheater outlet pressure with steam temperature of 485 °C with 5 °C variation for a bagasse-fired boiler in a sugar factory;
- with 8–10 minutes storage capacity of bagasse in the feeding chute and with a speed control in the feeder;
- with panel wall construction for bagasse plus lignite;
- with a complete cross-flow of the boiler bank for bagasse and lignite;
- with electrostatic precipitation (ESP) to reduce particulated emission bagasse;
- with the capability (multi-fuel) to burn various fuels other than bagasse and lignite, i.e., agrowaste, wood chips, etc.; and
- which operates at such high temperature and pressure with the combination of primary and secondary SH with convection and radiation characteristics to achieve the rated steam temperature in the 60–100% steam load range.

Expected Cogeneration Boiler Performance

The cogeneration boiler unit has to essentially fulfill the following enhanced expectations. It must have:

- higher steam pressure and temperature;
- higher steam purity;
- better combustion equipment;
- greater fuel flexibility;
- greater efficiency;
- better control automation; and
- better system reliability, uptime, and overall quality

Boiler Arrangement

Furnace and Grate

The boiler unit comprises a bidrum, natural circulation, radiant, top-supported arrangement used for firing bagasse and lignite, in combination or individually. The boiler furnace is a membrane-walled, water-cooled construction, adequately and conservatively sized to afford adequate release rates and residence time for complete combustion of both the fuels.

Both the fuels are to be fired on the travagrate. Since the capacity of the boiler is larger, a twin travagrate has been employed for the first time. for firing both the fuels.

Travagrates are driven by two separate hydraulic drives with separate power pack units. More than 160 units of this design are working smoothly all over the country, and it is expected that this type of grate will be able to fire the two fuels efficiently, either in combination, or one fuel at a time.

Since the boilers are meant for cogeneration, the complete furnace is used with panel walls of 2½ " outer diameter (OD) tubes of carbon steel with fins at a pitch of 85 mm, so as to reduce the radiation losses and to extract the maximum heat into the furnace. The advantages of the membrane wall furnace have already been elaborated separately. The furnace has been designed to fulfil the following requirements.

- A large enough surface area to reduce the temperature of furnace gases to a level acceptable to the superheating requirements
- Sufficient height to ensure adequate water circulation in the furnace tubes.
- A tube diameter sufficient to ensure a minimum friction drop, so as to avoid impedance to the flow of the steam–water mixture and to assure sufficient flow to avoid tube overheating.

Superheater

The superheater is a two-stage pendant type, vertically suspended, and has a combination of convection and radiation characteristics to achieve rated steam temperature in the 60 to 100% steam-load range. Attemperature of interstage spray type design shall maintain the close tolerance of temperature with variations in load range. The steam from the steam drum is taken to the primary steamheater consisting of 38 mm OD tubes with 4 5 mm thickness of a combination of carbon steel and alloy steel 311 material.

Interstage attemperator is utilized for temperature control by taking the primary steam outlet to the water drum, using drum coils attemperation without mixing, and then taking the steam to the secondary steamheater facing the furnace. The secondary steamheater is completely of alloy steel construction with combination of T11 and T22 material of 50 mm OD and 4.5 diameter mm thickness. This arrangement gives that characteristic with respect to the load. Sufficient mass flow can be maintained for steam so as to reduce the steamheater metal temperature at lower loads also. Boilers designed for cogeneration require very high degrees of superheat. This calls for the careful design of the superheater The design of such superheaters requires extra care to preclude steam and flue gas distribution differences which could lead to the overheating of the tubes. The mass flow selected depends on the steam pressure and temperatures as well as the superheater thermal duty. In addition, the higher pressure loss associated with higher velocities improves the steam side flow distribution, and, therefore, the superheater design must also conform to the following parameters.

- Use of an alloy of lower cost.
- Production of a more reasonable steam pressure drop without jeopardizing the tube temperature.
- A high mass flow to lower tube temperature.
- Tube spacings that minimize ash accumulation with various types of fuel.
- Permit superheater surface to be located in a zone of higher gas temperature with a subsequent saving in its area.

Convection Bank

The convection bank is a completely cross-flow arrangement. The spacing of the tubes is arranged so as to achieve maximum heat transfer with optimum draft loss and minimum erosion. The convection tube bank consists of the boiler bank placed across the steam drum and water drum with 50 mm OD tubes and a pitch of 102 mm across. Since the boiler has to be equipped for lignite firing, which has a higher ash content, a complete convection bank has been provided with complete cross-flow – an arrangement for the first time in a sugar factory in India. Generally, the convection banks are long-flow and two-pass. However, in this boiler, the convection bank is single-pass, across, and baffleless, as a result of which the losses due to turns are reduced and energy is saved. Also, refractory baffle maintenance is eliminated.

Economizer

The in-line bare-tube construction of the economizer raises feed-water temperature to the desired outlet temperature. Inlet water temperature to the economizer will be 105 °C, and, at the outlet, will be around 170 °C.

The economizer consists of 38 mm OD tubes, 4 mm thick, with an up-flow arrangement and a liberal pitch (75 mm), so that the possibility of erosion is very low. There is an arrangement for the provision of a grit inceptor at the inlet end of the economizer. The separated grit can be fired back to the furnace by the reinjection arrangement, thus increasing the efficiency of the boiler.

In the economizer design, it is advisable to limit the feedwater temperature leaving the economizer to well below the saturation temperature say by about 25–30 °C, as this will ensure adequate circulation. In case it becomes necessary to have a steaming-type economizer, the steam generated should be restricted to about three per cent by weight and separate special feedwater cyclones should be provided for steam separation to ensure safe circulation.

Air Heater

A tubular flue gas airheater is used as the last stage of heat recovery to absorb heat from the flue gas to heat the combustion air to the desired degree so that the grate components have a long life. The last few rows of airheater tubes are provided with corten steel in order to protect them from low-temperature corrosion. The air inlet temperature is 30 °C and the outlet temperature is 150 °C. This combination would cool out the flue gases after the air heater to 160 °C.

The air heater tubes are 63.5 mm OD tubes of 2.4 mm thick carbon steel, while the secondary pass is made of corten steel tubes to avoid corrosion due to low metal temperatures. This feature is also being incorporated for the first time in India. In view of the very high moisture content of bagasse, every effort should be made to get as high an air temperature from the air heater as possible, as this would help improve the combustion of bagasse in the furnace. Depending upon the grate material and type of grate, air temperatures varying anywhere between 170 to 200 °C can be achieved.

Gas Cleaning

ESP has been provided with minimum draft loss, minimum particulate emission, and with minimum power consumed by the induced draft (ID) fan.

Fuel Feeding

The firing system comprises a continuous ash discharge travelling grate, with variable speed drum rotary feeders and pneumatic spreaders for firing bagasse. A separate bagasse eile is provided for a 8–10 minute storage capacity so that fuel feeding is not affected even in case of problems with mills.

Bagasse Feeding

Two independent feeding systems for bagasse and for lignite have been provided at the front end. Bagasse is fed to the boiler by means of pneumatic spreaders for which around 0.3 m^3/second will be required at about 650 mm air pressure. Hot air from the air preheater is sucked in by a secondary fan and utilized for the pneumatic spreader.

Lignite Feeding

For lignite feeding, a conventional drag chain carries lignite fuel from the outlet of the lignite bunker provided at the front of the boiler. A separate emergency chute for emptying the bunker in case of a fire has also been provided as a safety measure.

Overfire Air

High-pressure over-fire with hot air has been provided with two rows each on the front and rear wall side to create adequate turbulence in order to achieve high residence time for complete combustion of a volatile matter in the furnace. The rich mixture of flue gases thus created further travels to the superheater and the convection bank.

As bagasse is a much lighter fuel than coal or lignite, with increased suspension burning, it becomes almost mandatory to employ an overfire air system including the header nozzle openings and duct-work sized for no less than 40% of the total combustion air requirement. Nozzle sizing and spacing is decided so as to get a minimum of 70% penetration. High-injection velocities are used to obtain an effective burnout of the combustion gases. The spacing and number of air nozzles are set on the free jet expansion principle. All nozzles are placed so that almost the entire furnace cross-section is covered while minimizing jet-to-jet and jet-to-wall interface.

Balance Draft

The boiler is designed to operate under balanced draft conditions and suitable dynamically balanced induced draft and fixed draft fans free of undue vibrations are provided.

Drums and Internals

The incoming feedwater heated in the economizer enters the steam drum and is well distributed across the length of the drum by means of a perforated pipe. The steam and wa-

ter mixture collected from each wall are separated in the steam drum by centrifugal vortex separators. The steam is further washed by chevron scrubbers to ensure high steam purity.

Steam purity assumes increasing importance with increasing boiler pressure. The carry-over of silica and deposition on turbine blades could cause severe problems. The control of boiler water quality, through the control of the quality of feedwater and requisite blow-down, is essential. The drum is fitted with high-efficiency steam/water separators and steam purifiers. Any compromise in the design or installation of these drum internals can cause problems not only in the turbine, but also in the superheater tubes due to the formation of scales causing high metal temperatures. Many operating units are found to be plagued with choked superheater tubes due to bad water quality and erroneous drum internals.

Advantages of the Travagrate Firing System

The advantages of the travagrate firing system are listed below.

- Flexibility of burning various fuels like bagasse, lignite, coal, wood chips, agrowastes, etc
- Complete automation including automatic combustion control to regulate bagasse flow and corresponding air control.
- The travagrate boiler facilitates quick response to load change as it retains the advantages of partial burning of bagasse in suspension.
- Air leakages are prevented because of the special grate design of the travagrate, which maintains low excess air and results in the higher efficiency of the boiler.
- Continuous ash discharge eliminates pressure fluctuations.
- The travagrate of the TBW design is the most robust, using special shell-moulded castings to ensure dimensional accuracy and maintaining close tolerances for long trouble-free operations.

That this is a superior design is borne out by the fact that more than 160 units with such travagrates are in operation throughout the country.

Advantages of the Membrane-wall Furnace

The membrane panel has the following advantages.

- Ensures a gas-tight enclosure which reduces leakage to an absolute minimum in the furnace. All guarantees and calculations are based on less excess air. This also reduces fuel costs.
- Reduces fan power requirements as reduced leakage means a lower volume of gas at a lower system resistance. Gas weights handled by the induced draft fan and draft losses would be less.
- Reduces furnace maintenance as it greatly minimizes slagging and its effects; as the membrane furnace stays free of slagging, low exit gas temperatures are maintained;

and as it simplifies tube repair. Although the wide-spaced tubes are relatively easy to weld in place, on the tube and tile wall, however, the heavy outer casing and tile must be removed and replaced. With the tangent tube wall, tube replacement is difficult as there is no clear space between the tubes for access, and the tubes must be cut loose from the bars and jacked out of line before ring welding, and then jacked back into place and reconnected to the tie bars. The spacing provided by the membrane wall permits in-place ring welding simply by burning through the membrane, with only the insulation and light gage lagging to be removed.

The operation and maintenance departments of the boiler makers and users should try to install systems with ISO 9001, ASME sell certification system, etc., thus ensuring the operation of thorough quality management systems.

With the increasing size of sugar plants and increasing prices of fuel, an overall urge for high efficiency can be clearly seen, and, therefore, there is an urgent need for more efficient boilers distinctively superior to the older designs.

TBW, backed by the world's largest boiler makers, Babcox & Wilcox, USA, is capable of offering the right technology and possesses the essential infrastructure as well. To meet the demands of cogeneration arrangements, a real multi-fuel boiler, with a high pressure of 66 kg/cm^2 and with a high temperature of 485 ^oC can be achieved with maximum possible efficiency and trouble-free service throughout the year.

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Selection of Steam Parameters for Cogeneration

A K Srivastava[1]

Introduction

Steam turbines have been used as prime movers for generators and other mechanical machinery ever since they were invented. The application for generation of power differs from other applications because, in power generation, the normal requirements are for a constant speed turbine, working at a fairly steady loading condition. In the other type of applications, the speed and the load may change considerably, the size of the turbine and the control systems as well. Cogeneration has a few additional requirements over and above those of speed and load variations. The reason is that a cogeneration power plant has to work in an industrial environment with a priority on process steam conditions. In other words, it has to face the worst possible conditions of operations and, therefore, the turbine design must be robust enough to withstand variations in several parameters without getting affected by them. A brief list of variations is presented below. However, it should not be taken as an exhaustive or complete list, as cogeneration projects do not have standard operating conditions.

- Inlet steam pressure
- Inlet steam temperature
- Inlet steam flow
- Extraction/back pressure steam pressure
- Extraction/back pressure steam flow
- Power cycles
- Load throw-off, part loads
- Sudden loading
- Frequency

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- Process optimization
- Power optimization
- Safety features
- Loading curves – hot and cold
- Control system

A detailed discussion on all these variations is not possible in a single paper. Therefore, this paper is restricted to the steam parameters at inlet and exhaust; some observations are also made on the control system. A general observation can be made on the basis of experience gained by GEC Alsthom worldwide in various cogeneration power plants. Smaller turbines withstand the vagaries of these variations much better. Most of these variations cause thermal and mechanical stresses at a very high rate of change, which can lead to local distortions in the rotor and casing. A small turbine has very low thermal inertia; it dissipates heat at a very fast rate and remains unaffected by these changes. A slower rate of heat transfer through the body of larger machines can lead to localized stress, which is injurious as it can lead to uneven expansions.

Steam Parameters

Inlet steam parameters normally used for small industrial power plants vary between 40 to 106 bar(a) in pressure and 400 to 520 °C temperature. There are various combinations possible within these limits of pressures and temperatures. Selection of these parameters is normally dependent upon the fuel and the type of boiler used in the plant. However, in a cogeneration plant, there is one more aspect which has to be analysed in further detail, i.e., the exhaust steam condition. The exhaust steam conditions vary from industry to industry depending upon their process steam requirements. For example, in paper plants, process steam is required at 5 bar(a), 12 bar(a), and 18 bar(a), whereas in a sugar plant the requirement is at 7 bar(a) and 2.5 bar(a). The optimization of the turbine being closely related to these exhaust/extraction steam conditions, this aspect of design also cannot be generalized for all cogeneration applications. We can only lay down some criteria and precautions for optimization. This will be done through the consideration of a specific case.

The exhaust condition becomes difficult when steam pressures are low, leading to very high volumetric flows. The case of 2.5 bar(a) used in the sugar factory illustrates this problem vividly. The set of conditions that we are going to analyse are listed below:

1. 40 bar(a), 450 °C;
2. 40 bar(a), 500 °C;
3. 65 bar(a), 510 °C;
4. 60 bar(a), 480 °C;
5. 80 bar(a), 510 °C; and
6. 106 bar(a), 520 °C.

We are considering a high efficiency turbine for this application because the revenue out of the saving or selling of power has to be maximized in a cogeneration plant

Assumptions for Analysis

A few assumptions for the analysis are listed below.

1. Fuel quantity entering the boiler is constant for all the steam conditions considered here. Consequently, there will be some change in steam output from the boiler depending upon the final enthalpy of the steam produced. Consider a flow of 70 tonnes per hour (tph) for 40 bar(a), 450 °C as a basis for comparison.
2. A flow of about five tonnes is taken as first extraction in the pressure range of 10 to 12 bar(a).
3. A back-pressure turbine is being considered with an acceptable pressure of 2.5 bar(a) with 10 to 15 °C super heat.
4. Exhaust steam having no super heat is not acceptable because process heating requires that a certain degree of super heat be present in the exhaust; line losses have also to be accounted for.

Consider parameter 1, for a high efficiency turbine working at 40 bar(a), 450 °C, the exhaust steam is at a temperature of 133 °C at 2.5 bar(a), and power output is approximately 10 MW. This is the lowest power output of all these conditions, as we shall see later We will use it for comparison.

With parameter 2, i.e., 40 bar(a), at 500 °C, the inlet enthalpy of this steam is comparable to 65 bar(a), 510 °C, but the exhaust steam is available at a temperature of about 180 °C. This creates two problems.

- 180 °C is a very high degree of super heat and is, therefore, not suitable for process heating unless additional equipment for desuperheating is installed, with the consequential loss of power in this process
- The volumetric flow at exhaust is very high – approximately 15 m^3/second. This means that a higher frame of turbine may be chosen to pass this steam. The power output of this turbine is 11 MW, which is less than that achieved in parameter 3 where a smaller turbine generates about 12 MW.

This means that we would be using a bigger turbine with a smaller output of power, and very high exhaust steam temperatures. Therefore, this option is not the optimum one.

One more aspect to be analysed in this situation is the actual drum pressure for achieving a temperature of 500 °C at the outlet of the superheater. It may be considerably more than the line pressure; therefore, the requirement of a good water treatment plant may still exist. This may be further discussed with boiler manufacturers.

At 65 bar(a), 510 °C, we get about 67 tph of steam with the same fuel and the turbine produces 12 MW power. The exhaust steam has a temperature of 139 °C at 2.5 bar(a). Between this parameter and the first one, there is a gain of 2 MW with acceptable exhaust conditions. This 2 MW of power, with a 60% load factor and Rs 2.25/kWh, provides additional revenue of approximately Rs 2.3 crores per annum. The difference in project cost would be in the range of Rs 3.5 crores which can be ammortized in less than two years. Therefore, it may be preferable to select the inlet steam condition of 65 bar(a), 510 °C out of the conditions discussed so far.

Parameter 4 is not acceptable because the outlet steam is almost saturated at 128 °C. Parameters 5 and 6 also give saturated steam at 2.5 bar(a) and are, therefore, not acceptable

Thus, analysing the exhaust conditions and power output against incremental rise in project cost, it may be logical to choose 65 bar(a), 510 °C. Other situations of exhaust and extractions may be similarly analysed for the determination of optimum steam parameters for cogeneration applications.

Control System

A steam turbine (Figure 1) used in a cogeneration process delivers electric power through a generator and thermal power through the extraction line. Generally, there is no direct relation between electric power (We), and thermal power (Wt), and they can vary in operation sometimes with very large amplitudes To adjust We and Wt, the turbine requires two different control systems operating separately.

The electric power controls the inlet flow through a system of inlet control valves V1, and the thermal power is adjusted by the pressure in the extraction line, which is controlled by a system of integrated valves V2. The total power output is dependent upon the steam flow through both the portions of the turbine.

The size of turbine is determined by the steam flow at its various ports. The surplus power output in cogeneration applications is only the second priority. For this purpose, it is beneficial to specify the most frequently used range of steam conditions. For example, in Figure 1, there may be a requirement for a very large flow from valve V2 for a short duration. If the turbine is designed for this extreme condition, which occurs very infrequently, then valve V2 will have to throttle a large amount of steam during its normal operation. The throttle loss may be of the order of two per cent. Considering a 20 MW turbine, it means that about 400 kW of power is being wasted continuously. The low-pressure portion of the turbine in this case is also oversized for this application, which may cost more but will deliver full output only for short durations. A turbine running at lower than its designed rating loses efficiency. Such a situation should be avoided if possible.

In Figure 1, we have considered internally controlled extraction. This type of control is better when the process requires fairly constant pressure with a large change in flow. However, if it is acceptable to have about 15% change in pressure, and the flow is very

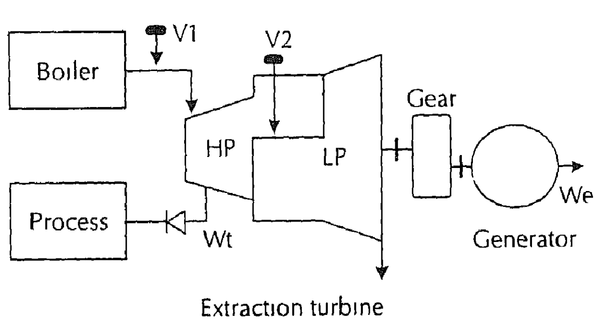


Figure 1. *Internally controlled extraction*

small, then it may be economical to have an uncontrolled bleed point in the turbine. The required pressure accuracy may be achieved in this case by having an external pressure reducing and desuperheating station (PRDS) in parallel.

Internal control is achieved through digital governors very easily. These governors are capable of controlling the following parameters in an intelligent manner, with the safety of the turbine given top priority.

- Inlet pressure in parallel with grid
- Extraction pressure
- Back pressure, when in parallel with grid
- Maximum power generation in parallel with grid
- Frequency control in isolation
- Rate of speed variation
- Changes in modes of control by automatic inputs

Conclusion

The selection of steam parameters has both a technical and a commercial basis. In cogeneration applications, where large quantities of steam are extracted for the process, it is essential to check whether the extracted steam can be used directly in the process without a further loss of power because of PRDS. Extraction conditions are dependent upon inlet parameters and turbine efficiency and, hence, it is important to determine these parameters in such a manner that power output is maximized within acceptable limits of extraction pressure and temperature to suit the process application.

Tea Industry: Technological Options for Combined Heat and Power Systems

Sanjay Mande,[1] V V N Kishore

Introduction

India is the largest producer of tea in the world, accounting for about 28% of world production, with an estimated annual production of 720 million kg of tea. Two processing methods, the cut-tear-curl (CTC) method and the orthodox (classical) method, have generally been adopted by tea manufacturers. Around 56% of manufacturers use the CTC method and the remainder use the orthodox method.

The production of tea from green leaves is essentially a gradual oxidation process. After harvest, green leaves go through the following stages: (i) withering; (ii) rolling and cutting; (iii) fermentation; (iv) drying; (v) grading and packing.

Energy Use Scenario in Tea Industry

Energy is used at various unit stages in the processing of tea. In initial years of the industry, only wood was utilized for thermal applications, as dense natural forests existed around plantation areas. As time passed, forest cover gradually decreased and the industry started utilizing other fossil fuels. In 1989, total fuel consumption for drying 720 million kg of tea was as follows (Deb 1990):

- coal: 0.50 million tonnes (mt);
- fuelwood: 0.25 mt;
- T D oil: 40 000 kilolitres (kl);
- furnace oil: 20 000 kl
- diesel: 25 000 kl;
- leco: 15 000 tonnes; and
- natural gas: 5 million Nm^3.

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For the operating machineries used for tea processing, lighting, irrigation pumping, etc., the tea industry consumes more than 500 million units of electricity per year. Since grid electric supply is not reliable, all tea estates have captive diesel gensets consuming about 80 000 kl of diesel annually. The installed capacity of gensets in the Indian tea industry is about 2000 MW.

The major fraction of energy consumed in tea processing is spent in the drying process. This process comprises an air heater, a feeding system for tea, a dryer, blowers with associated ducting, and cyclone separators for removing tea dust in the hot flues. Old factories use continuous tray dryers, but these are being replaced by fluidized bed dryers in modern large-scale tea factories. A thermal analysis of these systems shows that, though the performance of the dryer system has considerably improved due to technological innovations, there has not been a significant improvement in the efficiency of air heater (TERI 1992). The thermal and electrical consumption figures for the present tea drying process are shown in Table 1 (Palaniappan 1988).

It is apparent from Table 1 that drying consumes the highest fraction of energy. As mentioned earlier, coal is the main source of energy in the north-eastern estates while fuelwood is predominantly used in southern estates. With the increased availability of oil and natural gas, the northern estates are utilizing more and more of it, though the southern estates still use firewood grown in captive forests. A more serious problem faced by the tea industry is the frequent power cuts, which is a regular phenomenon in hill areas where tea gardens are generally located, making the grid electric supply unreliable. Hence the use of diesel gensets has become a necessary practice in tea industry. From the above discussion, it is apparent that a combined heat and power (CHP) system would be highly desirable for the tea industry. Some technological options for CHP systems are described in the following sections.

Table 1

Average thermal and electrical energy consumption at various stages in tea processing

Processing stage	Energy consumption			
	CTC		Orthodox	
	Thermal (kWh/kg)	Electric (kWh/kg)	Thermal (kWh/kg)	Electric (kWh/kg)
Withering	0 70	0 11	1 08	0 14
Drying	3 80	0 04	3 30	0 04
Others[a]	—	0 45	—	0 40
Total	4 50[b]	0 60[c]	4.38	0 58

[a] rolling, fermentation, grading and packing, [b] range evaluated 3 78 – 5 22; [c] range evaluated 0 55 – 0 65

Some Technological Options for CHP Systems

Industrial use of CHP or cogeneration systems leads to small, dispersed electric power generation installations – an alternative to complete reliance on grid power supply. Fuel saving is the major incentive for the use of CHP systems. Since all the heat engine based electric power systems emit heat into the environment, this emitted heat can be used to meet all, or part of the on-site local thermal energy needs. Use of rejected heat usually has no effect on the amount of primary fuel used, yet it leads to a saving of the fuel that could otherwise be used for the thermal energy process. Heat engines also require a high temperature thermal input and, in some situations, can obtain the input thermal energy as the rejected heat from a higher temperature thermal energy process. In the former case, the cogeneration process employs a heat engine topping cycle; in the latter case, a bottoming cycle is used. CHP systems can be designed from two perspectives: they can be sized to meet the process heat needs and the electricity produced is treated as a by-product, or they can be sized to meet electrical power demand and the rejected heat is then used to supply process heat needs.

The most common heat engine systems for CHP systems are:

- steam turbines (back pressure and extraction type configurations);
- combustion gas turbines (open or closed cycle type); and
- diesel engines

Each heat engine type has unique characteristics that make it better suited for CHP applications than others. For example, engine types can be characterized by:

- power to heat ratio at design point;
- capacity range;
- power to heat ratio variability;

Table 2

Cogeneration characteristics for heat engines

Engine type	Steam turbine		Combustion gas turbine	Diesel engine
	Extraction condensing type	Back pressure type		
Efficiency at design point	0.25–0.30	0.20–0.25	0.25–0 30	0 35–0.40
Part load efficiency	Fair	Fair	Poor	Good
Multifuel capability	Excellent	Excellent	Poor	Fair to Poor
Maximum temperature of recoverable heat (°C)	93–315	93–315	538–649	260–371
Recoverable heat (kcal/kWh)	280–8800	4300–17600	800–2800	100–1600
Typical power to heat ratio	0 10–0.30	0.05–0 20	0 30–0 45	0 60–0.85

- part load (off-design) efficiency; and
- multi-fuel capability.

The major heat engine types are described in terms of these characteristics in Table 2 (Perry, Green 1984). Representative CHP systems for each heat engine type are described in the following sections.

Steam Turbine Systems

Both back pressure and extraction condensing steam turbine systems can be used. The back pressure configuration is better suited for applications in which the power to heat ratio is low and relatively fixed. Extraction condensing steam turbines offer greater variability of power to heat ratio (through changes in the amount of extracted steam) and a higher power to heat ratio (when extracted steam is minimized). The extraction condensing cycle must always condense the steam flow which passes through the full pressure ratio of the turbine; the extracted steam may or may not need to pass through the condenser, depending on the temperature limits of the heat and whether or not it condenses the steam flow. For the back pressure configuration, the need for a condenser depends on whether the heat load itself condenses the steam flow or not.

Combustion Gas Turbine Systems

Gas turbines operate on the Brayton cycle. In a combustion turbine, a clean fuel is burned directly in the compressed air working fluid and the combustion products are then expanded through the turbine and exhausted to the atmosphere. The combustion gas turbine system provides a higher power to heat ratio than a typical steam turbine configuration (see Table 2). Of all the systems considered the combustion gas turbines also provides heat at the higher temperature (up to 650 °C). A major drawback of combustion gas turbine systems is their poor part-load efficiency and the requirement for clean fuel to avoid erosive or corrosive damage to the turbine.

Diesel Engines

Diesel engines have been used in small-scale cogeneration applications. They are characterized by high engine efficiency (see Table 2), good part-load characteristics, a relatively low rejected heat temperature, and a high power to heat ratio. Diesel engines supply process heat in two forms: low temperature (93–121 °C) engine coolants, and higher temperature (260–370 °C) exhaust gas.

CHP Systems for the Tea Industry

A typical tea garden producing 4 lakh kilograms of tea annually is considered here to calculate the power to heat ratio, in order to decide which CHP system is suitable for its operations. It is assumed that a dryer having capacity of 300 kg/hour of made tea is in-

stalled in this tea factory. The amount of hot air needed for tea drying at 120 °C for a Pandian plug flow tea dryer (the value is taken from their product catalog) is 9.5 × 10^3 Nm^3/hour. This is, therefore equal to 11.4 × 10^3 kg/hour. The amount of heat required to heat air from 20 °C to 120 °C will be: 273 600 kcal/hour ≈ 318 kW (thermal). Electrical power required for rolling, fermentation, grading and packing, etc., will be: 0.6 × 300 = 180 kW.

For a typical tea garden, the amount of electricity required for lighting (factory and residential campus within tea garden), irrigation pumping, flour mills, etc., is about 50 kW. Thus, the total electrical power needs of a tea garden having one tea dryer of 300 kg/hour capacity will be 230 kW. Hence the power to heat ratio is 230/318 or 0.72.

Therefore, referring to Table 2, it can be seen that the diesel engine cogeneration system is the most suitable option for the tea industry. The schematic diagram of the diesel engine cogeneration cycle is shown in Figure 1.

Potential of Wood Gasifier Systems

Tea estates at present depend on firewood grown in captive forests due to the insufficient and unreliable supply of coal and leco. Captive diesel gensets are used to meet roughly 40% of electricity demand. These gensets consume large quantities of diesel every year, prices of which are rising sharply and steadily due to acute shortage in the hilly regions of South India. Wood gasifier systems can be used to obtain producer gas which can in turn, be used to run the diesel genset of the CHP system on a dual fuel mode in order to replace 65–75% of the diesel consumed resulting in large savings of diesel oil. This will make the diesel genset CHP system more attractive due to reduction in costs, and due to the fact that existing diesel gensets can be used for this purpose, needing less additional capital investment. Figure 2 shows a detailed flow chart of diesel engine CHP system for the tea industry utilizing wood gasifiers.

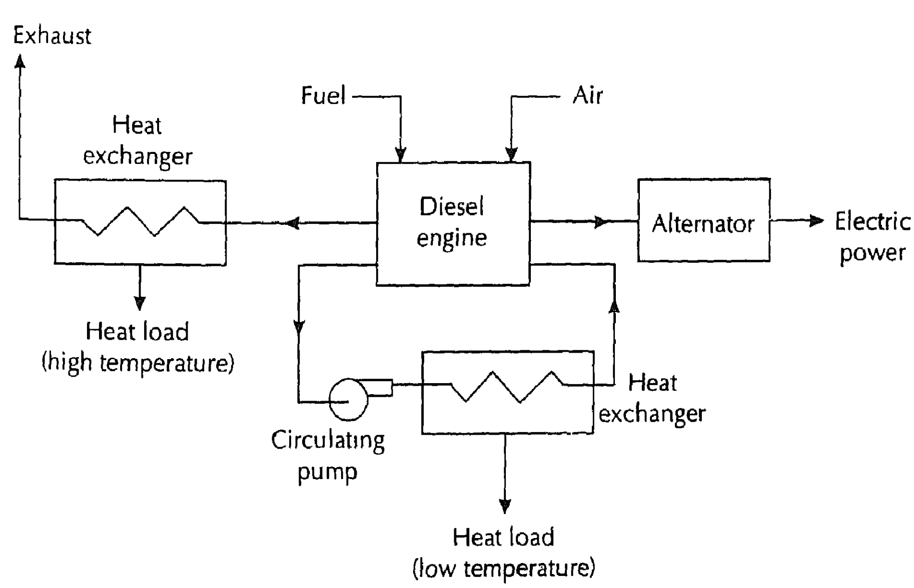


Figure 1. *Diesel engine cogeneration cycle*

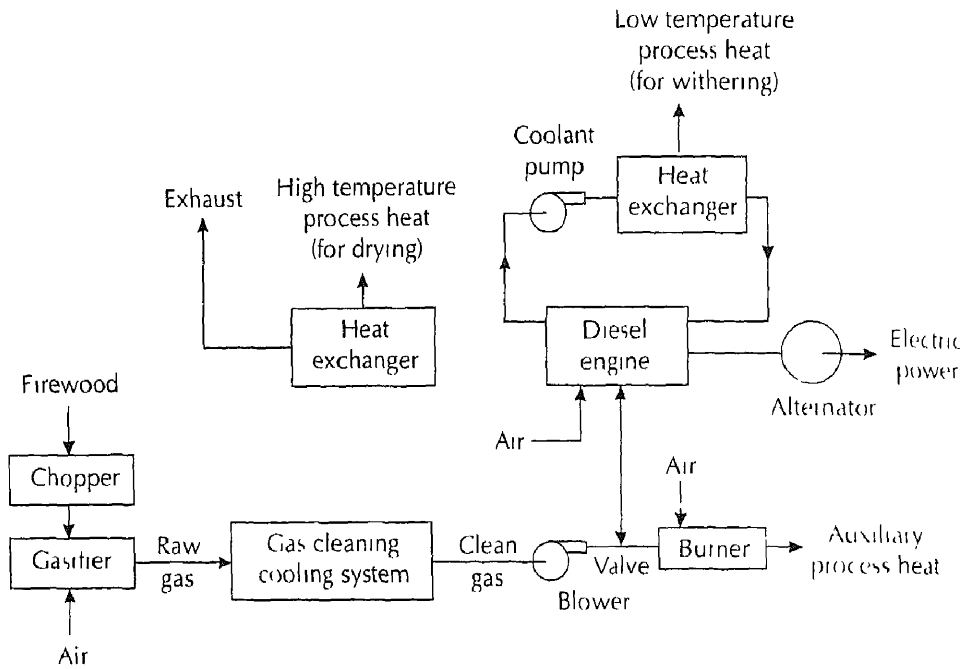


Figure 2. *Wood gasifier based diesel engine cogeneration system for the tea industry*

Conclusions

Tea processing is an energy-intensive process requiring large quantities of thermal energy for drying and electrical energy for operating machinery, lighting, irrigation pumping, etc. Of the several CHP options available, the diesel engine cogeneration system is found to be the most suitable for meeting the process heat and power requirements of the tea industry. Induction of the wood gasifier system in diesel engine CHP systems makes such systems highly economical and desirable

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Session VII

Indian Experiences in Cogeneration

Cogeneration Power Plant Set up for the Chemical Complex at Mithapur

V P Pahuja[1]

Since its inception in 1939, Tata Chemicals Ltd has undergone innumerable trials and tribulations and has surmounted many hurdles through the sheer dedication and perseverance of its employees along with its inspired leaders, to emerge as the single-largest soda ash producer in the world by the synthetic route It has also the largest inorganic chemical complex not only in the country but in this part of the world as well.

The concept of cogeneration of steam and power for the chemical complex was adopted since the inception of Tata Chemicals In 1939 there were no facilities available not even roads worth the name, and there was only one metre gauge rail line going up to Port Okha Tata Chemicals had to, therefore build everything for their requirement and their survival

For any chemical process, there is either an exothermic reaction where heat is generated, or an endothermic reaction where heat is consumed. In order to provide for such heat transfer, the best medium selected is steam. Based on this principle, we sized our steam and power plant in such a manner so as to generate steam at a higher pressure (in our case at 110 kg/cm^2 and 515 °C) generate power through high pressure turbines, which we call as topping turbogenerators (TGs), and exhaust steam from these turbines at 30 kg/cm^2 Part of the steam at 30 kg/cm^2 is used to drive CO_2 compressors and boiler feed pumps, and is also used in steam-heated calciners. The balance steam passes through low-pressure turbines with extraction facilities to draw steam at 10 kg/cm^2 pressure, 3 5 kg/cm^2, and the balance at the back pressure of 1 kg/cm^2. All these streams of low-pressure steam are used in various plants for heating purposes.

We do not work any condensing turbine where the latent heat of the lowest pressure steam would be lost into the sink. This total energy concept in our cogeneration steam and power plant gives us an overall thermal efficiency as high as 70%. During any unbalanced conditions of plant operations, when the steam and power demands do not match, we have provided pressure reducing and desuperheating stations to meet the demand at the required pressure and temperature conditions. Our turbine governing sys-

[1] Tata Chemicals Ltd, Mithapur, Okhamandal, Distt Jamnagar, Gujarat - 361 345, India.

tem is also provided with both speed and back pressure controls, which can be switched over from one to the other. In addition, we now have a tie-up with the Gujarat Electricity Board (GEB) to supply or draw power to or from, the grid, as per our plant conditions. This tie-up was initiated with the intention of supplying our surplus power to GEB, but once in a while due to upset plant conditions, we do draw some power for short durations. Our present installed capacity of steam and power is 550 tonnes per hour of steam and 55 MW of power.

In 1992, we took up the installation of a cement plant at Mithapur, started the expansion of soda ash from 700 000 tonnes/year to 1 million tonnes/year, and also added a new caustic soda plant of 100 tonnes per day based on membrane cell technology. All this required additional power and steam. Hence, we decided to go in for a new boiler and TG set. We selected the boiler with the latest circo fluid bed combustion technology and ordered the boiler from M/s Krupp Industries India Ltd, Pune, who are in technical collaboration with Lurgi Lentjes Babcock Energietechnik GMBH, Germany. The boiler has steam generation capacity of 200 tonnes per hour at 112 kg/cm^2 pressure and 565 °C temperature. We were the first in India to place an order for this type of boiler of this large a capacity and temperature rating.

This boiler is a tall tower type boiler with membrane walls and minimum flue gas velocities of 3–5 m/second required for fluidization, maintaining/combustion temperature in the bed up to a maximum of 950 °C, and capable of burning either coal or lignite without any adverse effects of slagging. The generating tubes, superheaters, and one economizer are suspended inside the furnace, which absorb the maximum amount of heat before the flue gases go to the cyclones, where the maximum temperature is 450 °C. In fluidized-bed combustion boiler terms, these are called cold cyclones. In order to capture sulphur in lignite, this boiler is provided with a limestone feeding system which reacts in the bed at temperatures below 950° to form $CaSO_4$, and the stack emission for SO_2 can be controlled to 100 ppm. As the furnace temperature does not exceed 950 °C, the formation of NO_x automatically remains within 100 ppm, meeting the latest pollution control norms. Particulate emission is controlled to less than 150 mg/Nm^3 by a large electrostatic precipitation (ESP). We have a continuous stack monitoring system for particulate emissions, SO_x, and NO_x.

The TG set for steam inlet conditions of 110 bars and 565 °C was obtained from Bharat Heavy Electricals Ltd (BHEL). The turbine was rated to generate 16.5 MW power with a back pressure of 30 kg/cm^2. In order to design the turbine for a 565 °C temperature rating, BHEL had to take the help of Siemens, Germany, as all the utility power plants in India have a maximum temperature rating of 545 °C.

Our circo fluid bed boiler was first commissioned in January 1995. After initial teething troubles, we were able to run the boiler for a few weeks, after which we decided to shut it down and carry out an inside inspection to make sure that everything was fine. We then found that the refractory lining in the furnace portion as well as in the cyclones had totally peeled off. On investigation, it was found that the refractory material supplied was of poor quality. We consulted Associated Cement Corporation (ACC) experts and selected an alternative material, the application of which was supervised by ACC. It took us two months to restart the boiler.

Thereafter, we had a few tube leakages in the economizer section, and in the superheater and water wall areas, due to the poor quality of the materials and poor workmanship, which were attended to as and when the leakages occurred. During these

incidents, once the bed got flooded, and, the second time, the water from the economizer tube leakage got carried over the first ESP hoppers, which then required thorough cleaning.

Subsequently, we encountered a few tube leakages in the superheater and economizer sections that are suspended inside the furnace. Those leakages were due to the heavy erosion on the outer surface of the tubes. This was attributed to a certain misalignment of the coils and the inappropriate shielding of the tubes from the impact of ash in circulation. Representatives from M/s KILL, Pune, and M/s LLB, Germany, were called on to sort out these problems. The rectifications as suggested by them were carried out and the boiler is now running smoothly.

It is over an year now since the boiler first started working and the average availability so far has been 60%. We did achieve a full rating of the boiler and the performance tests, both on lignite and coal as fuels, were carried out. The thermal efficiency calculated was over 88% for coal and over 87% for lignite, which exceeded the guaranteed figures.

Conclusion

After some teething problems, this system has now been stabilized, and is running well above the guaranteed efficiencies.

Cogeneration at the J K Paper Mills

B T Sridharan[1]

Introduction

Indian industry is facing an acute power shortage today. In some states, industries are being subjected to power restrictions to the tune of 50 to 70%. Even in the states where the power position is comfortable, peak load restrictions are imposed and, for continuous process industries, there is always a danger of overload tripping/low voltage. The cogeneration potential available in the country is around 15 000 MW in the industrial sector. If the power can be tapped, it will not only ensure an economical and attractive option but could also contribute to the betterment of the environment, which is a very important factor nowadays.

The industrial sector in India today accounts for about 45% of the total consumption of electrical energy. There are industries where both steam and electricity are required. These industries, such as the fertilizers, textiles, petrochemicals, paper, cement, and ceramics industries, can opt for cogeneration as it offers certain benefits to industry. These benefits include:

- generation of total energy requirement internally and freedom from dependence on external agencies;
- the surplus energy generated can be supplied to the state electricity boards at competitive prices; and
- reduction of the overall greenhouse gas emissions and, hence, reduced air pollution.

In any process industry, steam is widely used for heating/drying either directly or indirectly and to run the prime movers with varying pressures and temperatures. Steam is usually generated at higher pressure and temperatures than required for the process. To bring higher pressure steam to the required level, steam is expanded in a steam turbine and extracted at the required pressure and temperature.

The steam turbine is coupled with the generator to produce power for the internal consumption of the industry. This simultaneous generation of power and steam for process use is called cogeneration.

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Cogeneration is widely applicable in the pulp and paper, sugar, fertilizer, textile, rayon fibre, and petrochemical industries. In the paper industry, steam is mainly used for cooking of wood chips in digesters to make pulp, for drying paper in the paper machines at different pressures and temperatures, and in evaporators for chemical recovery in black liquor (BL).

In the JK Paper Mills, with an installed capacity of 75 000 tonnes per annum (tpa) paper production, cogeneration is extensively used for process. Saturated steam at 10 kg/cm^2(g), 200 °C is required for the digesters and for the bleaching plant for pulping, and at the recovery boilers for air preheating. Steam at 2.8 kg/cm^2(g), 150 °C is required for the paper machines, the coat plant, and the laminating machines, at the pulp drying plant for drying, at the evaporators for increasing the concentration of weak BL, and at the deaerators, the causticizing plant, and the chlorine dioxide generating plant.

Present Status of Cogeneration at the J K Paper Mills

Coal-fired Boilers

Presently, steam is generated from coal-fired (CF) boilers of various capacities (see Table 1) at 36 kg/cm^2(g), 400 °C with a maximum cumulative steam generation capacity of around 112 tonnes per hour (tph). The boilers are generally operated at a thermal efficiency of around 78 to 80%.

All the four CF boilers are of the bidrum, water tube, natural circulation type with the integral furnace design, and are provided with superheaters with a spray type attemperator and economizer. Two deaerator feed tanks, each 2.3 m in diameter and 5.5 m in length, with a storage capacity of around 19 m^3 are provided, which can cater to all the four boilers' generation under MCR conditions for 16 minutes. All the four boilers

Table 1

Details of CF boilers (existing)

Description	CF boiler 1	CF Boiler 2	CF Boiler 3	CF Boiler 4
Make	Steinmuller	Steinmuller	Walchandnagar Industries Ltd	Walchandnagar Industries Ltd
Type of combustion	FBC boiler (converted in 1994)	FBC boiler (converted in 1994)	Travelling grate spreader stoker	Travelling grate spreader stoker
Year of installation	1962	1962	1981	1986
Working pressure (ata)	36	36	36	37
Working temperature (°C)	410	410	410	410
Maximum continous rating (MCR) (tph)	30	30	22	30
Feedwater temperature (°C) to economizer	102	102	102	102
Gross calorific value (GCV) of design fuel (coal) (kcal/kg)	3500	3600	5251	4000

have a common feedwater system with two deaerators and five feed pumps. The delivery headers of the feed pumps of both feed tanks are interconnected. Normally, deaerator capacity should cater to 20 minutes of boiler capacity at MCR operating conditions.

These boilers adopt the balanced draught system with dedicated forced and induced draught fans. These boilers are provided with separate mild steel bunkers for the storage of coal. All CF boilers are provided with furnace draught control, drum level control, and superheated steam temperature control.

Coal-fired boilers No 1 and 2 are provided with dedicated electrostatic precipitators supplied by Bharat Heavy Electricals Limited and connected to a 40 m high common steel chimney to which the BL fired boiler No. 3 is also connected.

The CF boiler No. 3 is provided with dust cyclones and is connected to a RCC chimney 40 m high. The CF boiler No. 4 is also provided with dust cyclones. The CF boiler No. 4 and the liquor-fired boiler No. 4 are connected to a common RCC chimney 53 m in height.

J K Paper Mills had experienced lower output from CF boilers Nos 1 and 2 due to persistent grate problems and the poor quality of coal. The thermal efficiency of the boilers was also low. Hence, they modified these boilers to replace the chain-grate stoker with the fluidized bed combustion (FBC) system in 1994.

The modification to FBC conversion involved:

- removal of the existing grate, the ID fan and FD fans, and the secondary fans;
- addition of an extra heating surface in the bed coils;
- modification of furnace tubes for boiler start-up;
- addition of an LDO firing system for better start-up;
- addition of the flue gas system and air preheaters with suitable ID and FD fans relocated as per requirement;
- installation of individual electrostatic precipitators;
- installation of dense phase fly ash collection system with a common steel silo;
- installation of a new coal handling plant; and
- modernization of instrumentation.

The above modifications improved performance of the boilers. The details of the CF boilers are given in Table 1. There is also a chemical recovery boiler (Liquor-fired boiler No. 4) of 300 tonnes per day (tpd) dry BL solids firing capacity from which steam is generated at 37 kg/cm^2(g), 400 °C.

Liquor Fired Boiler (LFB-4)

This boiler, supplied by the Bharat Heavy Electricals Ltd and commissioned during 1988, is designed to handle 300 tpd of dry BL solids. This is a combustion engineering design boiler, employing the suspension drying of BL (for further details, see Table 2).

The boiler is of the top-mounted, natural circulation, bidrum, fusion-welded membrane panel type construction with screen tubes, two-stage superheaters, and a boiler bank. A spray type desuperheater is located between the primary and secondary stage superheaters. This is provided with a twin cascade evaporator for secondary evaporation of BL from the evaporator plant. A twin chamber electrostatic precipitator is installed for recovery of chemicals from flue gas.

The requirement of power at JK Paper Mills is met by captive power generation (cogeneration) from 2.5, 5.4, and 12 MW turbo sets and power from the Orissa State

Table 2

Components and corresponding capacities of LFB-4

Description	Capacities
Furnace dimensions	
Area (m^2)	17
Depth (mm)	4292
Width (mm)	3937
Firing capacity (BL solids) (tpd)	300
Calorific value of BL (on dry basis) (kcal/kg)	3100
Concentration of BL to cascade evaporator (%)	50
Superheated steam flow (kg/h)	27 000
Superheated steam pressure [kg/cm^2 (g)]	37
Steam temperature (°C)	410 +/−8
Feedwater temperature (°C)	102
Water for desuperheater (kg/h)	1310

Electricity Board (OSEB) The average peak power requirement at present production level is about 14.3 MW. After the installation of 12 MW turbogenerator (TG) sets and considering the shutting down of the 2.5 MW TG set, the generation is 9 MW. This is about 60% of the power demand and also meets the process steam requirements. After the commissioning of the new CF boiler No. 5, the generation is expected to be about 14 5 MW. This cogeneration will fully meet the power requirements of the plant with the excess steam being condensed at the present production level. Dependence on the SEB will also cease.

The 2.5 MW set is a double extraction and condensing set supplied by Siemens, designed for an inlet steam pressure of 37 ata at 400 °C, externally controlled medium pressure (MP) steam extraction at 26 ata, and internally controlled low pressure (LP) steam extraction at 3.8 ata. Presently, MP extraction is dummied. The maximum LP extraction and condensing potential from this set is 19 and 7.2 tph respectively. The speed of the turbine is 8000 rpm and that of the alternator is 1500 rpm.

The 5.4 MW set is a double extraction and condensing set supplied by Blohm + Voss and designed for inlet steam pressure of 36.3 bars at 400 °C, with an internally controlled MP steam extraction of 11.3 ata and an internally controlled LP steam extraction at 3.7 ata. The maximum capacity of MP and LP extractions and condensing possible is 20, 30, and 17.5 tph respectively.

The 12 MW TG set is a double extraction-cum-condensing set manufactured by Gorlitz, Germany, designed for inlet conditions of 44 kg/cm^2(g), 450 °C. However, the turbine has been modified to suit steam parameters of 36 kg/cm^2(g), and 400 °C. The speed of the turbine and the alternator is 3000 rpm. The total steam and power balance is given in Figure 1.

Proposed Expansion

After the mill expansion, when the total paper production will rise to 160 000 tpa, the steam and power requirement will rise to 170 tph and 30 MW respectively. To meet this increased steam and power requirement for the mill, plans are afoot to go in for further cogeneration so that the cost of power generated in-house would be much below that of

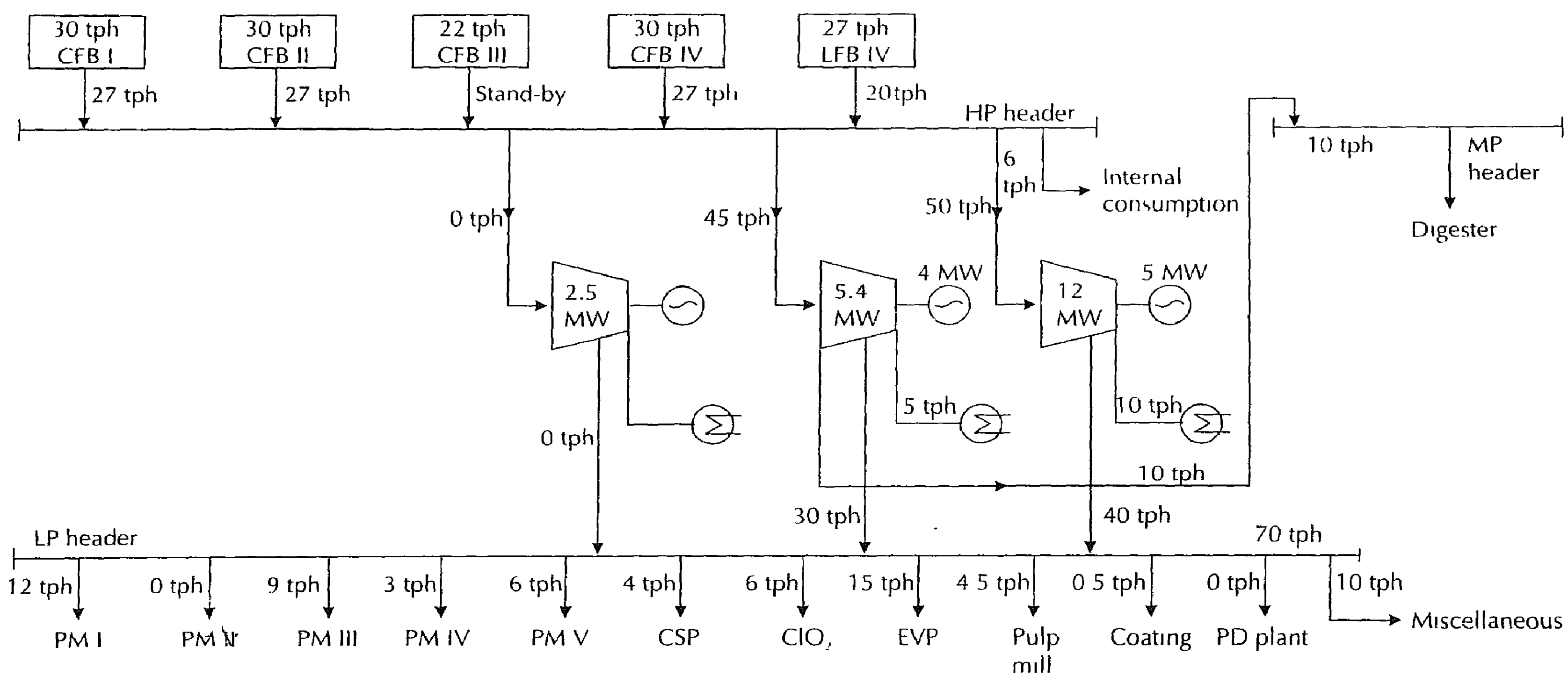


Figure 1 *Steam and power balance (75 500 tpa production)*

purchased power from OSEB, besides doing away with the grid. Also, cogeneration will help in substantial savings in energy, which is very vital nowadays.

To meet the entire 30 MW power requirement of the mill, the anticipated power generation through process steam (cogenerated power) is around 15 MW or about 50% of the total power demand.

In order to meet the balance power requirement of 15 MW, around 56 tph is to be condensed, utilizing the condensing facility available with all turbo alternators including a new turbo alternator for generating about 10 MW and the remaining 5 MW from the state grid.

Based on the above computation, the steam generation requirement from the proposed CF boilers is 121 tph after accounting for steam generation from existing CF and liquor-fired boilers and the proposed two recovery lignite fuel (LF) boilers 5 and 6. Accordingly, the cumulative installed capacity of CF boilers of 150 tph is selected to build up necessary margins required to meet the fluctuations in the steam generation of the chemical recovery boilers and for control purposes.

To meet 121 tph steam, a new 60 tph boiler has already been ordered which is scheduled to be commissioned by August 1996. It is proposed to have a new 90 tph (CF boiler No. 6) MCR boiler to meet the balance steam requirement considering the requirement of two boilers, CF Boilers 1 and 2. One boiler of 30 tph will be kept as a stand-by to take care of any breakdown and annual inspections of any boilers. In the proposed expansion, the details of CF boiler are given in Table 3.

During the annual inspection of the new boilers (CF boilers 5 and 6), the mill may have to draw more power from OSEB to meet the power demand.

The total power requirement after the expansion of the mill is around 30 MW and is proposed to be met by generating:

- 4.6 MW from the existing 5.4 MW TG set;
- 10.2 MW from the existing 12 MW TG Set; and
- 10.2 MW from the proposed new 12 MW TG set.

The anticipated steam and power balance of the mills after expansion is given in Figure 2.

Table 3
Details of the CF boilers (proposed)

Description	CF Boiler 1	CF Boiler 2	CF Boiler 3	CF Boiler 4 (proposed)
Make	Steinmuller	Steinmuller	TBW	—
Type of combustion	FBC boiler (converted in 1994)	FBC boiler (converted in 1994)	FBC	FBC
Year of installation	1962	1962	1996	1998
Working pressure (ata)	36	36	37	37
Working temperature (°C)	410	410	410	410
MCR (tph)	30	30	60	90
Feedwater temperature to economizer (°C)	102	102	102	102
GCV of design fuel (coal) (kcal/kg)	3500	3600	3500	3500

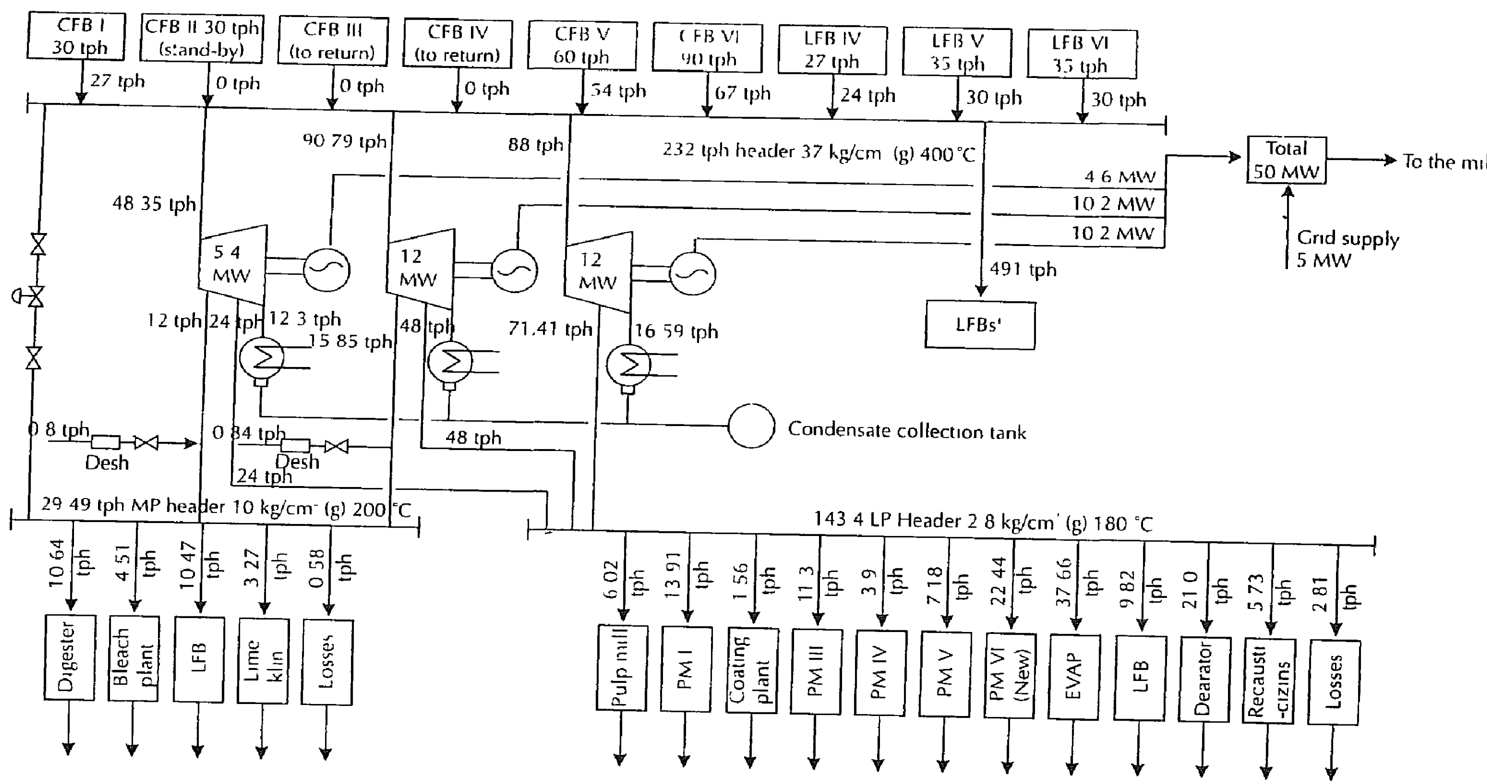


Figure 2 *Proposed steam and power balance*

Waste Heat Recovery from Flue Gases with Substantial Dust Load

J M Chawla[1]

Introduction

A lot of energy gets wasted as flue gas in cement, steel, and non-ferrous metallurgical plants, electric arc furnaces, refractories, and other associated industries. Most of the flue gases, with temperatures between 250 and 450 °C contain substantial amounts of dust and have to be quenched in a gas-conditioning tower by the complete evaporation of water before leading the gases to the bag filter or to the electrostatic precipitator (ESP).

The quantity of water required for conditioning of gases in a medium-sized cement factory may be of the order of 40 tonnes per hour. Scarcity of water and power in many parts of the world, especially near cement factories, demands heat recovery from the flue gases for power generation and the reduction of water consumption required for quenching the flue gases.

The conventional heat exchangers employed for heat recovery from gases in the cement industry, for instance, have very low efficiency due to scaling caused by heavy dust loads. High dust concentration in the flue gases may also lead to the complete choking and failure of the system.

Caldyn has invented and developed a new system called THERMOWIR, which makes use of a principle called MULTIWIR. This has been practiced by Caldyn successfully for the elimination of dust particles and droplets from flue gases.

The products developed by Caldyn for the scrubbing and energy technique are listed below.

1. The scrubbing technique

   - Pneumatic nozzle CSL
   - Spray drier ST

[1] CALDYN, Inc., (Sales Office), 16802 Timberline Drive, Strongville, Ohio 44136, USA.

- Quenching tower QN
- Desulphurization plant ABR
- Scrubber with aerosol enlargement CALWIR
- Dropleteliminator MULTIWIR

2. The energy technique

- CO_2 evaporator CL
- Air-conditioning with heat recovery FRESHERCON®
- Two-stage air-conditioning system for boats CLM
- Heat recovery system THERMOWIR

THERMOWIR: The Principle

THERMOWIR is designed specially to recover the waste heat available in flue gases with substantial dust loads. The heat transfer tubes are kept constantly clean by applying the principle of multiple cyclones. A number of small cyclones are generated within a staggered packing called MULTIWIR. A MULTIWIR-packing consists of parallel plates, which are fixed at a particular angle to the gas flow. The gas flow is divided into narrow streams, which cross each other through the structured packing. As a result of the reciprocal transfer of momentum in a transverse direction in relation to the principal direction of flow, the streams induce a rotational motion in each other. Due to the centrifugal force, the solid particles are thrown from the center of the channel to the walls of the MULTIWIR.

The heat transfer tube (Figure 1) is placed exactly in the middle of the channel, so that it remains almost dust-free. Dust is collected on the walls and in the corners of the packing and is removed from the packing periodically.

MULTIWIR represents a combination of staggered packing and multi-cyclones. The number of spinning streams in practice is very large (several thousands). The vortices also increase the heat-transfer coefficient. The gas side-pressure drop is kept within tolerable limits.

Power Generation with Waste Heat Recovery

One of the major applications of THERMOWIR is the generation of steam to drive turbine/generator sets for power generation. THERMOWIR can be successfully applied (Figure 2) to generate steam and as a prededuster. More than 60% of the dust can be taken out of the gases prior to the ESP.

Figure 2 shows the layout of the captive power plant for a cement factory. Water is heated to saturation temperature and a part is evaporated to become steam within the THERMOWIR. An externally fired boiler and superheater are added to the system to take care of the fluctuating flue gas temperatures and to superheat the steam to the desired value of ~430 °C.

Superheated steam of 34 bars pressure and 430 °C is led to drive the steam turbine-generator unit. The turbine-generator unit can be equipped with an air-cooled condenser, thus saving huge amounts of water. Preliminary calculations have revealed that ~6 MW

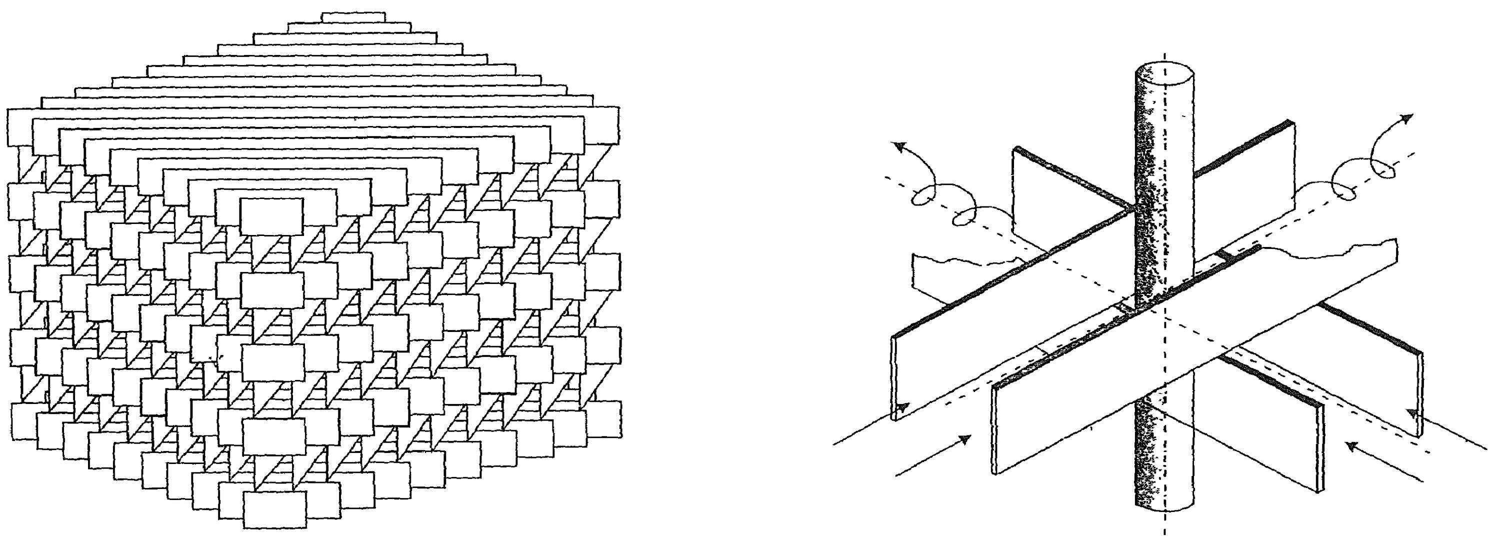


Figure 1. *Caldyn THERMOWIR: waste heat recovery from flue gases with substantial dust load*

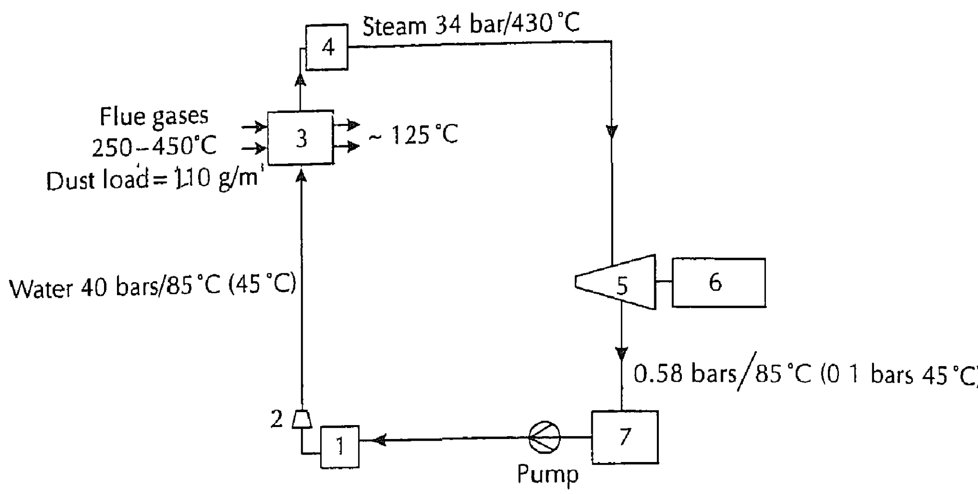


Figure 2 *Layout of a captive power plant for a cement factory; 1· Watertank; 2· Feed pump; 3: Waste heat recovery THERMOWIR; 4: Externally fired boiler and superheater; 5: Turbine; 6: Generator; 7. Air (water) cooled condenser*

electric power can be generated out of waste heat in a cement factory of 1 million tonnes capacity per year. Water saving is of the order of 200 tons per year.

Economics of the System

A computer programme is developed to compute the payback period for the investment required for the captive power plant (Figures 3a and 3b). The payback period for most of the cases is less than five years.

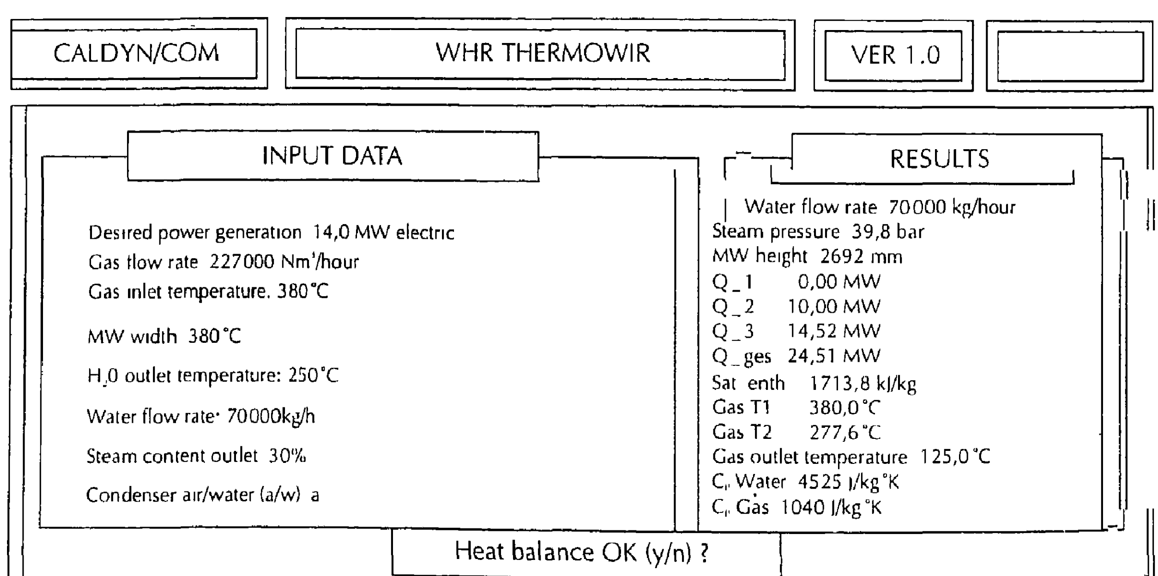


Figure 3a *Computer programme developed to compute the payback period*

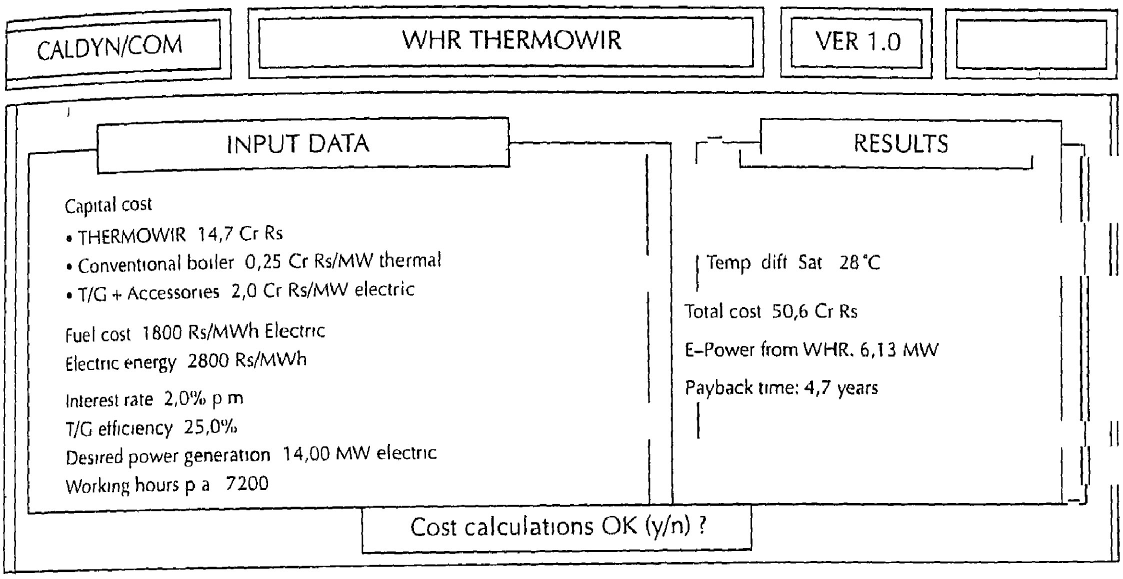


Figure 3b. *Computer programme developed to compute the payback period*

The first plant of this kind in a cement factory in India has been financed under the PACER scheme by the US Government. This plant, with a capacity of 2.6 MW electric, of which 1.6 MW will be out of waste heat recovery, is being erected at present at Dhar Cement, Jeerabad (near Indore), Madhya Pradesh, India.

Cogeneration from Waste Gases Emanating from Kilns in Sponge Iron Plants: Operation and Problems

V P Agarwal[1], K C Sood

Introduction

While direct reduction (DR) of iron core through the coal route has been estabilized, the focus here is on the optimization of operations while recovering the waste heat contained in the hot waste gases emanating from kilns. This paper discusses this waste heat recovery which can be specially utilized for power generation in sponge iron plants.

The Waste Heat Recovery System

Almost 100 000 Nm^3/hour of waste gases at 1000 °C emanate from 150 000 tonnes per annum module of a DR plant, which, in any conventional plant, are cooled, cleaned, and emitted into the atmosphere.

At Prakash Industries, a waste heat recovery system (WHRS) has been incorporated to recover the sensible heat contained in waste gases, and, thereby, generate steam. This steam is then led to steam turbines for generating electric power. Power thus generated caters to the total electricity demand of the DR plant, the raw material preparation system, all the utility facilities, offices, residential areas, and two 3 tonne induction furnaces as well.

Out of the total heat generated from the coal and the reactions in the DR plant, only 35% is used in reduction. The balance is wasted; which is, therefore, a colossal waste of energy. The question that one needs to answer here, therefore, is: how much electric power can be generated per tonne of direct reduced iron (DRI)?

[1] Prakash Industries Ltd, Padma Tower 1, Rajendra Place, New Delhi - 110 008.

Generation of power depends on coal consumption and the quality of coal fed to the kiln. The same can be expressed in terms of fixed carbon consumption per tonne of ore fed into the kiln. The dependence of power generation on coal quality is illustrated in Figure 1. Therefore, a vast potential, exists for generating power from the kiln waste gases by providing a suitably designed cogeneration WHRS.

The huge loss of energy potential of these waste gases widely known. However, only ISCOR, South Africa, put up a waste heat recovery boiler (WHRB) for generating process steam, where the quality of steam was not of paramount importance. Some other firms have also made limited efforts to recover this sensible heat with varying degrees of success.

The major reasons inhibiting incorporation of a WHRB in coal-based units may be summarized as given below.

1. The managements of sponge iron plants want to concentrate on making iron rather than indulge in other activities as the process itself is complicated.
2. It requires additional capital.
3. The system had not been tried out and, hence, involved risks. Earlier trials by some units had not been very successful.
4. Other problems, linked with sponge iron making, include.

   - the governance of kiln operation by process parameters and metallization of DRI rather than the parameter of steam or power to be generated;
   - non-suitability of the steam quality for turbine application, during start-up;
   - any interruption of kiln operations disturbs the waste gas generation, which in turn, causes fluctuations in steam generation;

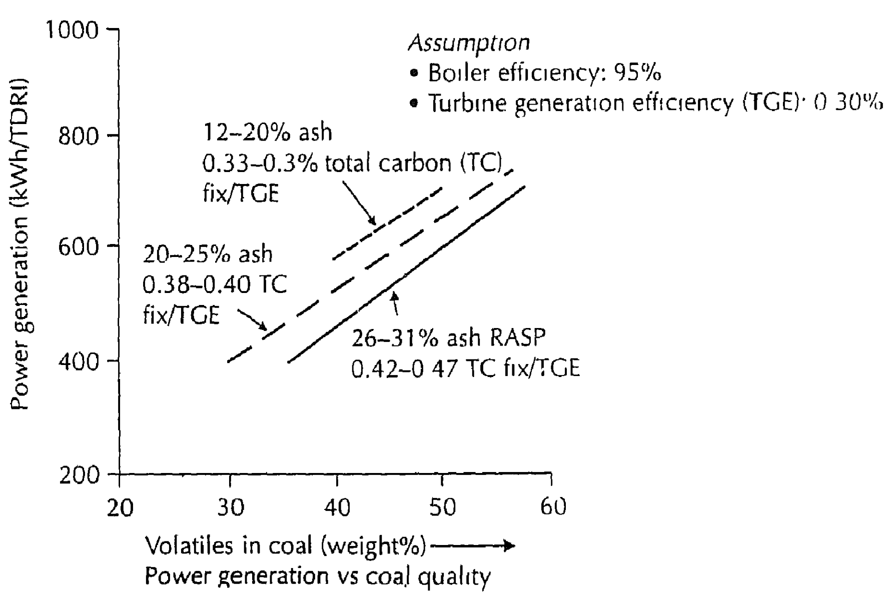


Figure 1. *Dependence of power generation on coal quality*

- the demand for steam depends on the load whereas the generation of steam depends on the health of kiln and its operation; and
- kiln waste gases carry about 35 to 40 gm/Nm^3 of dust particles.

In the case of waste heat recovery, the boiler is at the receiving end. The kiln operation is the primary operation and the WHRS is the passive portion of the combination. In normal boiler operations, the quality and quantity of steam is controlled by boiler firing, whereas, in this WHRS, the boiler has to operate and perform under conditions dictated by kiln operation parameters.

At times, during the DR plant operation, a few unstable conditions may occur or the kiln is placed on 'hold', under which condition, the emergency cap is operated and the waste gases allowed to escape through the emergency cap and a stage of no flow occurs at the WHRS. This is then followed by the closing of the emergency cap with the result that the entire quantity of gases rushes through the WHRS. Thus, there is a wide variation of gas flow from 'no flow' to 'full flow' and vice versa. The boiler must, therefore, be so designed that it can favourably respond to these wide fluctuations of the waste gas flow conditions.

In any power plant design, one is free to select the optimum steam parameters and procure a compatible turbogenerator. However, in the case of Prakash Industries, in order to restrict the capital outlay, it was decided to go in for a second-hand turbogenerator and the inlet conditions of this second-hand turbogenerator became the governing factor in selecting the boiler parameters.

Start-up

Further, during start-up, and also during the period when gas flow to the WHRS is under fluctuation, the condition of steam generated varies. Under these conditions the steam was not suitable to pass through the steam turbine. Provision had, therefore, to be made for condensing the entire steam thus generated. This problem has been overcome at Prakash Industries by providing an auxiliary condenser which was able to take care of up to 100% of the steam capacity. Here, the steam pressure is reduced in two stages at the pressure reducing and by the desuperheating station (PRDS). In the first stage, the pressure is reduced from 40 to 7.7 atmospheres and, in the second stage, from 7.7. to 1.1 atmospheres before the steam is passed through the auxiliary condenser (Figure 2).

Despite various odds and the peculiar requirements of the WHRS design, Prakash Industries ventured into incorporating a WHRB in the main process line.

Waste Gas Treatment

Waste gases have to be subjected to a waste gas treatment for conditioning with regard to their temperature, dust content, combustible constituents, and contaminants, before they can be used in a WHRS. These gases, from their rotary kiln, pass through a horizontal dust chamber located beneath the after-burning chamber (ABC), as shown in Figure 3. A dust-settling chamber reduces the waste gas velocity, and, thereby, removes large dust

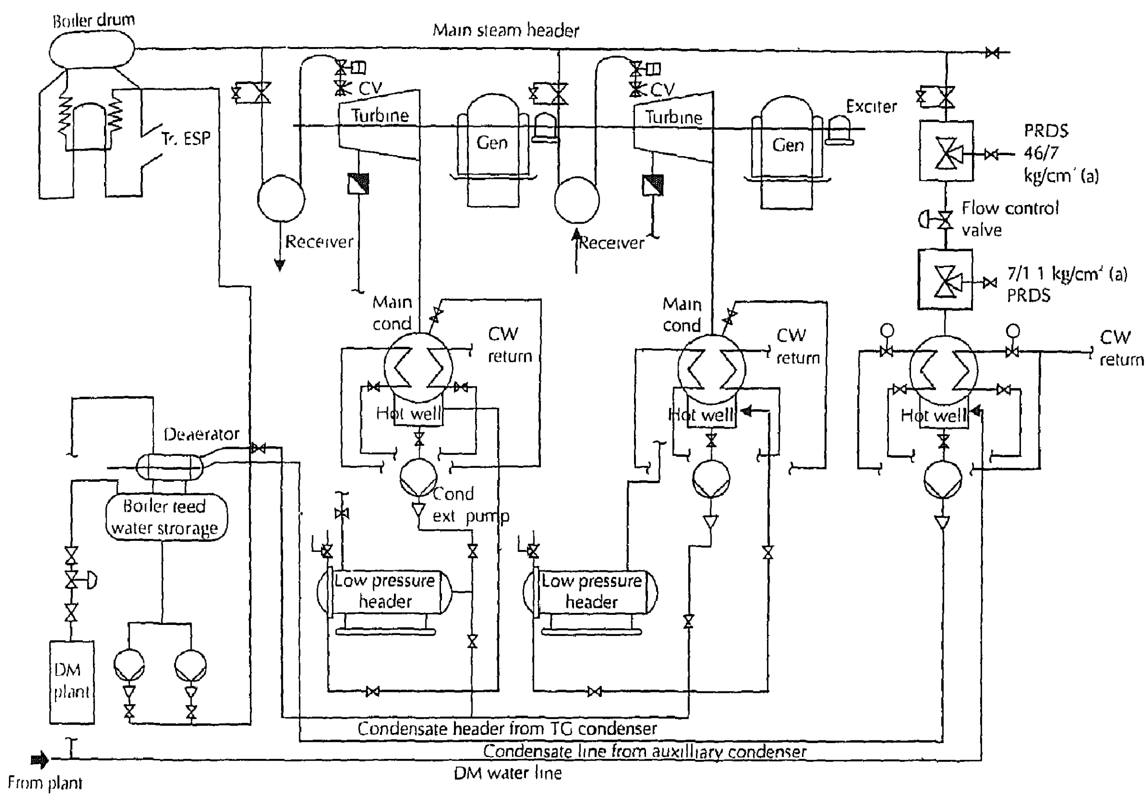


Figure 2. *A turbogenerator with an auxiliary condenser*

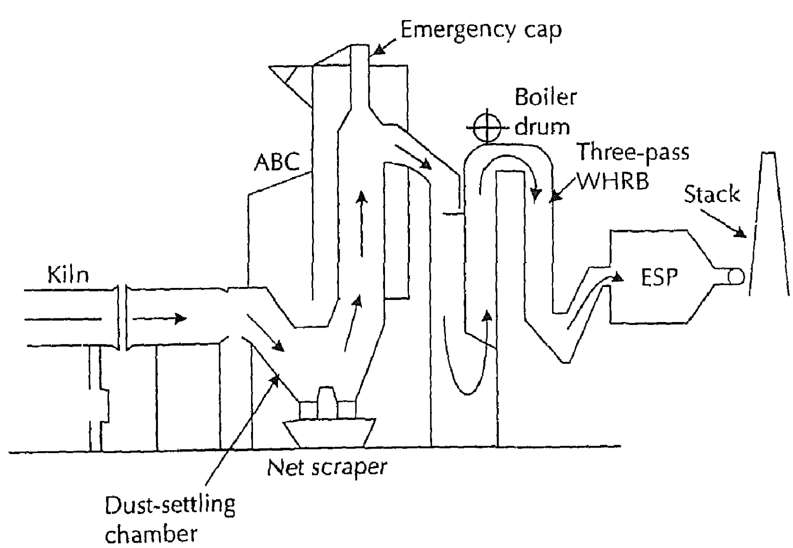


Figure 3 *A design sketch of a kiln with a WHRB*

particles by gravity, retards pressure fluctuation, and achieves uniformity in the waste gases with regard to temperature and to the concentration of combustible constituents. At the end of dust chamber, the waste gases change their direction of flow and move upward and pass into the combustion area of the ABC. A water nozzle controls the inlet temperature of the gas. Combustion in the ABC takes place at a controlled temperature range, between 950 to 1000 °C. It is ensured that gas leaving the chamber has no trace of any hydrocarbon, monoxides, soot, or tar components.

The waste gases emanating from the rotary kiln at 1000 °C are passed through the WHRB, where these gases are cooled to 200 °C and the heat thus recovered is used to generate steam, which is then used in the turbine to generate power.

The Components of a WHRB System

The WHRB system is a vertical, natural circulation, top-supported single-drum, water-tube, three-pass design. It is designed to generate steam at the rate of 46.8 tonnes per hour (tph); 52 kg/cm^2; and 410 °C with normal kiln exhaust flow passing through the unit. However, considering the present turbogenerator available, the steam pressure is limited to 45 kg/cm^2 at the main steam stop-valve with the feed-water inlet temperature at 130 °C. During normal load, the kiln exhaust gas of 96 400 Nm^3/hour at 1000 °C is expected to pass through the unit continuously. The WHRB is also designed to generate peak output during kiln peak load operations. During peak load the WHRB will generate 52.9 tph at rated conditions and the corresponding exhaust flow of 110 000 Nm^3/hour at 1000 °C. The main components of a WHRB are described below.

Water Wall

The water wall is the first heat transfer section of the WHRB and lies in the direction of gas flow. The entire section is made up of a water-cooled enclosure formed by a tube fusion welded panel or a fin-welded panel tube. The front and rear wall are continuous and connected to the top/bottom header, while the side walls are provided with headers which are connected to the steam drum by a supply/riser tube. The furnace section is a bolted buckstay for structural rigidity and suitable for negative pressure operations.

Superheater

The system includes two superheaters in the second heat transfer section in the direction of gas flow. This section consists of a plain tube assembly, inlet and outlet headers, and connected links.

Evaporator

Of the three evaporators in the system, the first evaporator is located in the second pass after the first superheater, in the direction of gas flow. It consists of an inclined coil assembly made of plain tubes, inlet and outlet headers, and connected links. The second and third evaporators are located in the third pass in the direction of gas flow. The evaporator coils consist of plain tubes which are similar to those in the first evaporator. The economizer section also consists of a plain tube assembly, inlet and outlet headers, and connected links.

Ducts and Expansion Joints

A suitable connecting flange .with an expansion joint at the boiler inlet and an ducting, with expansion joints between Passes 2 and 3 and Pass 3 casing duct up to the economizer. are provided.

Safety Valve

The safety valve set pressure is, at present, fixed to meet the current operating conditions of the steam generated (this matches the old turbogenerator set).

The Auxiliary Condenser and the PRDS System

The auxiliary condenser absorbs the entire steam generated from the WHRB unit through the PRDS from the time of initial start-up, until a steady state of operation of the rotary kiln, is achieved. The turbogenerator units are then put in one by one, depending on the availability of steam. Even with the two turbogenerators switched on, a certain minimum quantity of steam has to be passed through the turbogenerator bypass circuit to the auxiliary condenser in order to keep this circuit in a warmed-up/poised state.

Keeping the turbogenerator bypass circuit in the poised state facilitates the fast dumping of steam as and when one or both turbogenerator units trip due to their own faults, or as protection throws the entire steam out as surplus. This minimizes the effect of the pressure surge on the WHRB unit, thereby ensuring its stable operation.

Similarly, the sudden excursion of the main steam pressure due to changes in system parameters/malfunctioning of control elements, etc., in a WHRB unit cannot be totally ruled out. A provision has been made in the turbogenerator bypass control system to absorb such momentary/sudden pressure surges by increasing the quantity of dumping steam in the auxiliary condenser. This also protects the turbogenerator sets from the higher inlet steam pressure.

Conclusion

Every steam-generating unit is custom built. The design and construction of a modern steam-generating unit, and its successful and efficient operation, requires the close cooperation of many disciplines and various engineering skills. Figure 4 (see next page) provides the view of the entire cogeneration system.

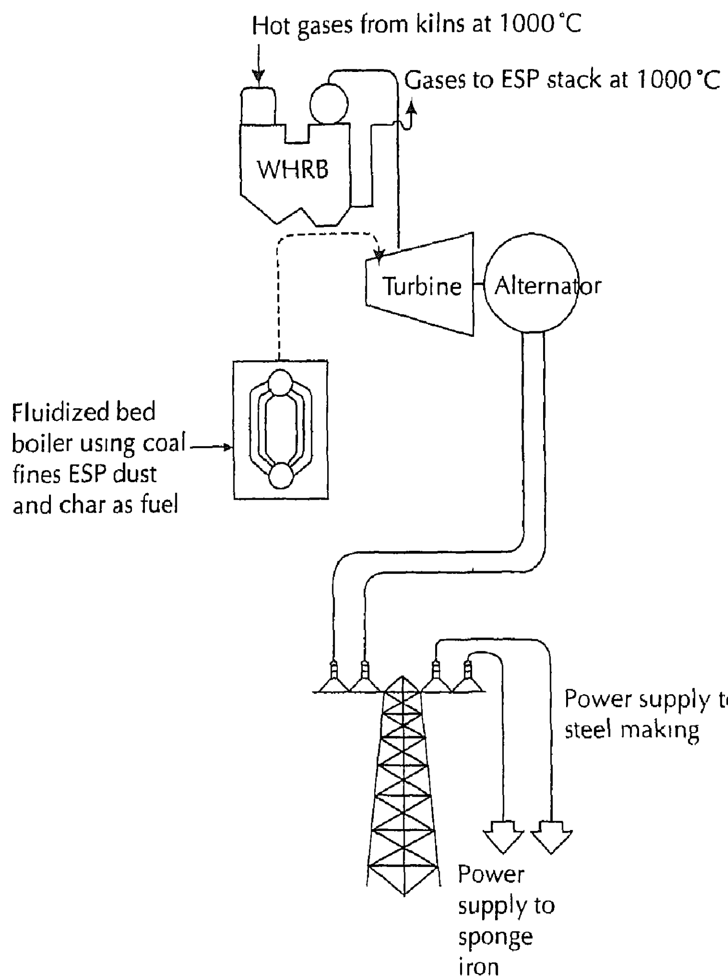


Figure 4. *Power generation from wastes and waste heat*

IPCL's Gas Turbine based Cogeneration Experience

B P Maradia[1]

Indian Petrochemicals Corporation Ltd (IPCL) is a major petrochemicals producing company, which was established in 1969. It started functioning initially using imported power from the state electricity grid and an emergency diesel generator (DG) set of 1.25 MVa capacity. On the subsequent expansion of the petrochemical plants, the need for captive generation was felt. During 1980–82, our electricity consumption was around 55 MW. We were dependent on the state grid for our entire power supply. The power interruptions and cuts, especially during the summer months, were a real bottleneck to our production targets. IPCL, therefore, went in for a 2 × 12.5 MW extraction condensing steam turbogenerator during 1982. Along with captive power generation, we have also initiated a scheme to isolate our generation from the grid whenever the latter was found unstable. IPCL power demand rose to around 65 MW during 1987/88, with the expansion of petrochemicals facilities, which, in turn, necessitated an increase in captive power generation. Gas turbine (GT) based cogeneration was identified as the most economical alternative available. Many options were available for recovering the waste heat from the GT – single/dual pressure heat recovery steam generators (HRSG), unfired/fired HRSGs, duct-fired/furnace-fired HRSGs, forced draft (FD) fan-supported air supply versus double capacity HRSGs to continue steam generation at the same production level when one of the GT trips, etc.

IPCL selected the option of dual fuel capability for the GT and the dual-pressure HRSGs capable of firing gas as well as liquid fuel. In case one of the GT trips, the other HRSG could then be supplementararity fired to double its capacity so as to maintain the same level of steam production from the cogeneration plant. The alternative of going in for the dual-pressure duct-fired option and of doubling the capacity when one of the GT trips has helped us in operational as well as maintenance simplicity, saving both space and capital investment. Since the number of dampers between the GT and the HRSG is

[1] Indian Petrochemicals Corporation Ltd, Baroda, India.

only one, the controls, protection, and interlocking has been simplified. Our HRSGs are the vertical gas path and horizontal water tube type. They have forced circulation and external drums connected with flexible headers to the economizer and evaporator blocks. The HRSG's erection time was reduced considerably due to its modular construction.

IPCL opted for the 2 × General Electric (GE) frame 6 (36 MW ISO) dual-fuel fired GT with Speedtronic Mark-IV controls; 2 × 50 + 20 (HP-IP) tonnes/hour, quick start, double capacity with supplementary-fired HRSGs from M/s HCG Holland; a 3 × 15 tonnes/hour fuel oil treatment plant from Alfa Lavel; and a distributed control and information system from M/s GE, USA (Datatronic DCIS).

IPCL commissioned and started commercial operations of the cogeneration plant in May 1988. The fuel gas to our units is supplied through the Hazira–Bijapur–Jagdishpur pipeline. With commissioning of this plant, IPCL has become self-sufficient on the power front and our dependence on the state electricity grid has reduced considerably, with power system stability increasing manifold. We have reduced our contract demand with the state grid from 65 to 35 MVa. This is just enough to take care of one GT outage. The installation of the isolation and load shedding scheme in 1992 based on the under-voltage relay to sense a voltage dip of 20%, under-frequency relay set to operate at 47.8 Hz, and the rate of change of frequency relay (df/dt) set to operate at 1.2 Hz/second, has brought down the incidences of total power failure to almost nil.

The cogeneration plant (Tables 1a, 1b, and 1c) has helped us achieve self-sufficiency and stability with a low energy index. Power stability, for a petrochemical complex of our size, is extremely important not only for economic production but also for the safety of the plants and personnel. The list of occasions that the IPCL electrical system could survive at time of the failures in state power supply or other major disturbances are listed in Table 2.

The total number of units generated in GT #2 was 1 509 660 MWh. A list of the spares consumed during combustion, hot gas path, and major inspections, along with the amount spent towards maintenance, is given below.

- I STG nozzle: 1 set
- II STG nozzle: 1 set
- III STG nozzle: 1 set
- I STG buckets: 2 sets
- II STG buckets: 1 set
- I STG shroud blocks: 1 set
- Modified TP: 1 set
- Gas-only nozzles: 1 set
- Diaphragm coupling: 1 no.
- HS quill brg (load gear): 1 no.
- Atomizing air compressor: 1 no.
- Total charges for spares: $1 980 500
- 30% custom duty: $594 150
- Total: $2 574 650
- Equivalent in rupees: Rs 79 814 150
- TA charges ($1 50 000): Rs 4 650 000
- Total amount spent towards maintenance: Rs 84 464 150
- Unit maintenance cost (1 509 660 × 1000): Rs 5.50/unit

Table 1a

Power generation data for the IPCL cogeneration plant

Year	GT#1 MWh	GT#2 (MWh)
1988/89	165450	82550
1989/90	117450	209570
1990/91	154970	227130
1991/92	258340	196910
1992/93	222260	238980
1993/94	258680	224830
1994/95	131360	167000
1995/96 (December)	179990	162690
Total	1488500	1509660
Total generation in MWh		
GT # 1	1488500	
GT # 2	1509660	
Total	2998160	

Table 1b

Power generation data for the IPCL cogeneration plant

	Average	1991/92	1992/93	1993/94	1994/95	1995/96 (January)	Total
GT # 1 generation (MWh)	214201 6	258148 0	222260 0	258680 0	131 4	200560 0	1071008 0
GT # 1 fuel consumption (msm^3)	64619 0	77 5	64 1	80922 0	42874 0	57 8	323 1
GT # 1 special fuel consumption (sm^3/MWh)	3031 2	300 1	288 3	31283 0	326 4	288 0	—
Total running hours	7420 0	8 2	7 9	8 5	5 5	7 1	37100 0
Availability (%)	—	93 3	89 8	96 8	62 4	96 7	—
GT # 2 generation (MWh)	201933 4	196 8	234 0	224830 0	167000 0	182150 0	1009667 0
GT # 2 fuel consumption (msm^3)	63 5	65 5	73 9	73 7	50486 0	54 1	317 6
GT # 2 special fuel consumption (sm^3/MWh)	313 7	332 6	308 6	328 0	302 3	297 0	—
Total running hours	7523 0	7774 0	8318 0	7722 0	7049 0	6753 0	37618 0
Availability (%)	—	88 5	9496 0	88 2	80 5	92 0	—

Table 1c

Power generation data for the IPCL cogeneration plant

	1991/92	1992/93	1993/94	1994/95	1995/96 (January)
HP steam to grid (tonnes)	869 4	865 1	891 5	601 3	715.8
LP steam to grid (tonnes)	80 7	78 6	67 9	68 1	68 9
Net power to grid (MWh)	451.4	457 8	479 1	294 5	378 9
Fuel gas to GTs (msm^3)	140 0	137 9	154 6	93 4	125.0
Fuel gas to HRSGs (msm^3)	4.5	3 1	1 2	4.5	1 6
Total gas (msm^3)	150 0	141 0	160 0	94 1	130 0
Calorific value (kcal/sm^3)	9 2	9 2	8 6	8 6	8 6

Table 2

Survival statistics of the plant

Date	Disturbance
23/5/91	At 6 04 hours, all the incomers tripped with the voltage dip exceeding 40%, fault at Gujarat Electricity Board (GEB) load dispatch centre
28/6/91	At 8.10 hours, tripping of 132 kV incomers at the GEB sub-station due to bus fault
25/10/91	At 10 55 hours, cascade tripping of the Maharashtra SEB and the GEB grid, rate of fall of frequency 1 2 Hz/second, the grid was unstable for almost 48 hours
15/11/91	At 15.32 hours, 33 kV incomers tripped on directional over-current, bus fault at GEB Jambuva LDC
15/6/92	At 19·28 hours, total power failure in the state
20/6/92	At 15.30 hours, voltage dip exceeding 40% observed, leading to isolation, lightening arrest or failure at the Nandesari sub-station
07/1/93	At 10 33 hours, 33 kV feeder tripping due to the failure of the bottom disc of the insulator at GEB Jawaharnagar
17/11/94	Isolation on under-voltage due to tripping of the IDI feeder on fault
25–29/11/94	Under-frequency isolations due to shortage of power in the state grid and low frequency operations
26/11/94	At 4 50 hours, tripping of 132 kV incomer at the GEB Jawaharnagar sub-station
01/12/94	At 11 42 hours, isolation due to low-system frequency
25/12/94	At 21.08 hours, tripping of the 220 kV line at GEB Jambuva
25/12/94	At 21 08 hours, tripping of 220 kV line at GEB Jambuva
14/1/95	At 19 13 hours, voltage dip, tripping of the Asoj feeder at GEB
20/1/95	At 13·57 hours, voltage dip due to a monkey fault at the GEB Calico feeder
2/3/95	At 20·14 hours, tripping of the 400 kV line at Bhillai-Kori and Jabalpur, inter-state grid disturbance
10/11/95	At 11 00 hours, fault at generating station in Madhya Pradesh, resulting in cascade failure
14/11/95	At 8 47 hours, under-frequency isolation due to overloading of grid
30/11/95	At 9 42 hours, under-frequency isolation due to the tripping of the 400 kV Asoj–Indore line
15/1/96	At 16:36 hours, flashover in the 33 kV breaker of the IDI feeder at GEB

Maintenance Summary

Scheduled Inspection Outage (GT#1)

Hot gas path inspection and Stage I; bucket change out; fired hours – 27 800 hours: During this inspection, the Stage I buckets, wh.ch were originally supplied along with the units, were changed, as per GE's TIL No. 1095-1 March 1991, and Til No. 1095–IRI, June 1991. Original Stage I Buckets supplied were P/N 932E0147 P005/P006, as per TIL 1095-1 and TIL 1095-IRI. These buckets, however, failed during service due to creep rupture strength, exacerbated by accelerated oxidation attack and high bucket metal temperature. The oxidation resulted from the deterioration of the external coating, and also by an internal oxidation attack of the uncoated cooling holes. This oxidation contributed to local over- temperature by partial plugging of cooling holes and subsequent reduction of creep life.

We were advised to replace the Stage I buckets with a new design – 932E0127P043/P044, equiaxed, GTD-111, 11-hole, GT-29 in plus-coated buckets. The parts changed during this inspection were a Set of TP and a set of bull-horn brackets.

Scheduled Inspection Outage (GT#2)

1. *Hot gas path inspection; fired hours: 15 090 hours.* Except for erosion on the TP photo frame and the TP side seal, the general condition of the hot-path components was excellent. During this outage, the field modifications for the atomizing air booster compressor isolation and the by-pass line in atomizing air cooling water were carried out.
2. *Hot gas path inspection and Stage I buckets change out (13 March to 15 April 1992).* The Stage I buckets were changed during this outage, as per GE's TIL 1095-IRI. During the hot gas inspection, the Stage I nozzle was found to be have an ecentricity of 10 mm. Cracks were found on the outer side walls and vanes. The cracks and eccentricity were within the inspection criteria. The oil leak from BRG #1 was also arrested by providing a new oil seal and the rotor float was adjusted from 0.025" to 0.017" by changing the active side thrust shim.
3. *Hot gas path inspection; fired hours – 38 884 hours.* This shutdown was mainly for changing the Stage I nozzle, which was not available with us during the last HGP. This inspection revealed the Stage II buckets Z seal (bucket shroud) creep deflection, and the subsequent locking and overlapping of shroud tips leading to cracks at some places (GE TIL No. 1067-3RI). It was decided to change the same at the major inspection. A set of modified TPs with TBC coating and flex seal (191E2572 G02 Rev 2) were replaced. Stage I shroud blocks that had cracks were also allowed to run till the major inspection.
4. *Major inspection; fired hours – 47 524 hours.* Stage I buckets 109E3033 P001/P002 were installed according to GE TIL 1147-1 January 1994. It has 12 cooling holes, GTD-111, and DS, with a GT-29 In Plus coating. A stage II nozzle 932E0144 G012 was installed as extensive cracking was observed on the outer side wall. Stage I shroud blocks 329A3228 G004 were also installed. During clearance measurements, a downward deflection of the Stage III nozzle was observed. A change was advised during the next outage. Foreign object damage, observed on the Stage I compressor

rotor, was repaired and the 17th stage compressor blade spacer was stacked (TIL 1090-2R2 March 1993).

5. *Stage III nozzle replacement.* During the last major inspection outage, a downward deflection of the Stage III nozzle was observed. Since the nozzle was not available, it was planned to change it at the next convenient opportunity. During this shutdown, the Stage III nozzle kit no. 948E0281G006 was installed. The alignment between the load gear and the GT was also checked. Shell cooling fans 88TK-1.2 were taken down from the turbine roof and installed outside the GT building.

Unscheduled Outage (GT#1)

The unit was commissioned on light diesel oil (LDO) on 5 April 1988, and later switched over to natural gas on 14 May 1988.

1. *4 July to 28 November 1989.* The unit tripped on a false fire alarm at 11:40 hours due to an earth fault in the fire detection system. After clearing the fault, the unit was put online at 20:25 hours. At 20:33 hours, it tripped on an over-speed alarm. The inboard seal and the inboard bearing of Shaft #1 were found damaged. The gear box casing had developed a crack in a vertical direction, running downwards around six inches. The investigation revealed the rolling of Shaft 1's inboard bearing, due to the locking of the accessory coupling, which was of the oil-filled type gear coupling from Zurn. The entire repair job, including metal stitching, resleeving, and assembling, was carried at SPIC, SMO at their Bombay workshop. As Shaft I was not available, metal spraying on the journal area was done at Indore. The unit was recommissioned on 28 November 1989.
2. *11 July to 16 July 1990.* The unit tripped on over-speed at 18:30 hours. The cause of tripping could not be established for a long time. Ultimately, it was suspected that the spring tension on the over-speed trip trigger might have reduced and the contact area for latching was not adequate. After improving contact area and increasing the spring tension, the assembly was refixed and put into operation. It continued to work well thereafter.
3. *8 October 1990 to 8 January 1991.* An abnormal noise from the accessory gear box was observed at 16:00 hours on 8 October; and, before any corrective action was taken, Shafts 1 and 2 were damaged. The gear box was checked for bearings bore alignment and concentricity. They were found correct. The cause of the failure was not exactly located, but the decision was taken to replace the gear coupling with diaphragm coupling. The unit was rolled after installing the new diaphragm coupling on 8 January 1991.
4. *15 May to 17 September 1994.* The unit tripped on the exhaust over-temperature followed by high vibrations. On investigation of the exhaust duct, the hot parts debris confirmed the major failure of the GT. The unit was stripped open. Stage II and III of the rotor, including Stage II and III of the stator, were completely damaged. The Stage I nozzle was found intact, while the Stage I rotor had a few broken buckets. There was a rubbing damage to the first five stages of the compressor stator as well as the rotor stages. The detailed destructive and metallurgical investigation at GE, USA, revealed the failure of the Stage I buckets (GTD-111, Equiax, GT-IN PLUS 932E0127 P043/044) due to creep failure. Originally, Stage I buckets

932E0147P005/P006 were installed on our machine. TIL 1095-1 and TIL 1095-IRI were issued to us during March and June 1991. Based on the advice given in this TIL, we changed our Stage I buckets in September 1992.

Further advice came through TIL 1147-1 asking the customer to change the Stage I buckets at 20 000 fired hours. However, the breakdown took place before we completed the predicted life of these buckets. The total repair job was given to Bharat Heavy Electricals Limited, including the supply of the compressor stator and rotor blades and the turbine Stage II and III buckets. During this outage, an alignment of the entire train was carried out. A generator retainer ring (18Mn-5Cr) inspection for cracks was also carried out. The unit was recommissioned on 17 September 1994.

Unscheduled Outage (GT#2)

1. *7 September to 14 September 1991.* The hydraulic filter started developing high differential pressure suddenly. The cause was attached to the leakage of lube oil cooler tube. The entire quantity of lube oil was drained and replaced. After locating the leaking tube and plugging, the unit was put back into service.
2. *10 October to 14 October 1995.* High vibrations were observed on the accessory gear box Shaft #1. The gear box was opened and inspected, which revealed that the thrust faces of Shafts 1 and 2 were worn out. The bearings were changed on all the shafts and the lube oil and hydraulic pumps were inspected. The unit was put back online on 14th.

General Problems and Solutions

Some of the general problems, and their solutions, are outlined below.

1. *Load gear compartment hot gas leak from exhaust plenum.* This is perennial problem, it requires frequent attendance. We generally pack the intermediate partition with ceramic wool blankets, which then lasts till next outage.
2. *High vibration on 88TK-1 and 2.* Attending to these fans installed over the roof of the GT was another recurring problem. The GT had to be brought down and run on part-load many a time, to take care of the wheel space temperature of the third stage during the outage of these fans. The final solution to this problem was to bring it out of the GT building. This has reduced the failure frequency and has made it very easy to monitor and maintain these fans.
3. *Atomizing air cooling.* While running on liquid fuel, the atomizing air circuit comes into line, putting an additional load on the cooling circuit. It is observed that the air temperature to the atomizing air compressor remains in the region of 135 °C. Continued operation, very near the alarm limit, damages the atomizing air compressor. We have had two such failures of compressors on each unit. Since the fuel gas availability at our complex is more or less uninterrupted, we always run on gas. We have blanked off the atomizing air circuit, and the compressors are taken out from the circuit to avoid unnecessary running and damage.

4. *Lube oil leakage from the high-speed (HS) quill oil deflector.* Load gear box HS quill shaft deflector leakage is another nagging problem. A modified HS quill bearing from GE, with a modified oil dam with a rotary oil sealing ring, has almost solved this leak. Moreover, by installing an additional vapour extraction fan to reduce gear box vapour pressure has helped in stopping this leakage from oil deflectors.
5. *Exhaust temperature high spread in Unit #2.* This is a peculiar problem related to this unit, which has an exhaust on the right-hand side (looking downstream). Due to the high spread, it has had to be operated quite often on part-load, or has caused downtime to check and reorient to replace the fuel nozzles. This problem is seldom faced on Unit #1, which has a left-hand side exhaust.
6. *Humming noise on HRSG 1.* This noise creates a persistent problem and causes tube vibration and rubbing with baffle plate, occasionally leading to tube failure. At every available opportunity, we tighten the holding down fixture bolts at the tube bends.

Evaluation and Utilization of 20 MW Cogen Power: a Case Study

M S Bhalla[1], H S Nagi

Introduction

A 20 MW cogen power plant is proposed to be set up at Simbhaoli sugar mill. Simbhaoli is a small town located on the Delhi–Meerut–Bareilly highway, is predominantly agricultural, and has no loads which could be classified as 'industrial'. Thus, for the utilization of the 20 MW output of the cogen plant, a survey of the areas in the neighborhood of Simbhaoli was undertaken and located within a radius of about 30 km, a growing industrial town – Gajraula. Gajraula is a semi-urban town, situated about 30 km from Simbhaoli and about 50 km from Moradabad (Manjhola). The load demands are predominantly domestic, commercial, and industrial. The distribution of power supply within the city and adjoining areas is the responsibility of the Uttar Pradesh State Electricity Board (UPSEB). However, due to the perennial shortage of power in the state, the existing power supply arrangements for the industrial factories are not quite satisfactory. The supply suffers from too many interruptions, which, in turn, affects the productivity of the industries located at Gajraula. Thus, Gajraula appears to be an ideal site for the absorption of the Simbhaoli cogen power output which is expected to be more reliable.

Existing Load Demand

Table 1 gives the list of major industries in and around Gajraula along with their sanctioned loads.

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Table 1

List of industries with sanctioned loads

Name	Load (MVa)
Power supplied at 33 kV	
Vam Organics	8 000
J K Pharmaceutical	2 900
Insilco	2 500
Ramganga Fertilizer	1 650
Best Board	1 200
Tirupati Texnit Ltd	1 400
J K Dairy & Food Ltd	2 000
Ranauq Automobiles	0 800
Ratan Vanaspati	2 000
Sri Acid & Chemicals Ltd	3 000
Total	25 450
Power supplied at 11 kV	
Kamakshi Paper Pvt Ltd	0.975
Kovel News Print	0 995
Shivalik Cellulose	0 950
Total	2 910

Status of Load Demands in the Gajraula Industrial Area

A quick survey of the load demands of some of the major industrial loads in the area indicated that 25.45 MVa of load is being drawn from the UPSEB grid at 33 kV, and about 2.9 MVA at 11 kV. The break-up of the industrial load demand, company-wise is given in Table 2.

All the comparatively larger industries have their own captive generator (DG sets) which serve as a stand-by to the UPSEB grid supply and are used whenever the grid supply fails. Vam Organics, however, in addition to 4 MVa DG stand-by generation, also have a steam-operated cogen plant of 2 MW capacity which meets the essential loads on a continuous basis. As per the present tariff, approximate electricity consumption charges that the industries have to pay to UPSEB varies between Rs 2.75/kWh to Rs 2.90/kWh. Data regarding load variation in some of the industries were also collected

Consumer's Perception Regarding Quality of UPSEB Grid Supply

The views of the operating personnel of the factories of some of the major industrial bulk electricity consumers in the Gajraula industrial area were invited with regard to the quality of grid supply received by them from UPSEB, based on their day-to-day experi-

Table 2

Companywise break-up of industrial load demand in Gajraula (Power supplied at 33 kV)

Name of the industry	Load maximum demand (MVa)	Product manufactured	Number of shifts	Captive generation
Vam Organics	8 00[a]	Adhesives	3	1 5 + 2.5 MW DG set
J K Pharmaceutical	1 50	Pencillin	3	2 x 1 MVa Diesel stand-by
Insilco	2 50	Dried silica (for the tyre industry)	3	2 x 1 MVa Diesel stand-by
Ramganga Fertilizer	1 65	Fertilizers	3	—
Best Board	1 20	Plywood	3	—
Tirupati Texnit Ltd	1 40	Undergarments		—
J K Dairy & Food Ltd	2 00	Dairy products	3	—
Ranauq Automobiles	0 80		3	—
Ratan Vansapati	2 00	Vegetable oil	3	750 kVa Diesel stand-by
Sri Acid & Chemicals Ltd	3 00	Paper, chemicals, and fertilizers	3	1160 kVa Diesel stand-by

[a]exclusive of 2 MVa steam generator output (cogen) which supplies the works on a continuous basis

ence. All the personnel interviewed expressed the opinion that the quality of grid power supply received by them was not satisfactory, both in terms of reliability as well as in terms of voltage and frequency.

As regards the reliability of grid power supply, it was gathered that interruptions occurred about 15–20 times a month and were of varying durations. The average figure quoted regarding the duration of the power supply interruptions was about 30–40 hours/month or 360–480 hours per year. This sort of unreliable power supply was playing havoc with their production schedules. They were, however, not able to furnish figures regarding the impact of these interruptions on the profitability of their business.

As regards the quality of supply in terms of voltage and frequency, we were given to understand that normally during the night hours, i.e., between 12 a.m. to 6 a.m., supply voltage and frequency were good. However, during the rest of the day, voltage and frequency deteriorate considerably and touch their lowest values (as low as 75 to 80% of declared voltage and frequency as low as 48.5 Hz) during the peak load hours from 6 p.m. to 10 p.m. Apart from these, during the agricultural season, when the power supply to the irrigation tubewells is given the highest priority by UPSEB, hours of interruptions to industrial consumers may touch a figure of 10–12 hours per day. During this season, voltage also remains low almost throughout the day due to the continuous working of the low power factor irrigation tubewell motors.

In sum, the general impression gathered on the basis of these discussions with the bulk consumers in Gajraula was that they would welcome more dependable power supply even at a higher price if the extra amount to be paid by them is not very much higher than UPSEB grid supply rates.

Existing T & D System in the Simbhaoli-Gajraula Area

Simbhaoli has a 220 kV grid sub-station under the jurisdiction of the UPSEB. This sub-station gets its power (470 MW) from the Narora Atomic Power Plant (NAPP), situated about 80 km from Simbhaoli over the 220 kV single circuit (S/C) line. The 220 kV Simbhaoli grid sub-station is also connected by a 50 km 220 kV single circuit line to Meerut (Modipuram). From the Simbhaoli 220 kV sub-station, four 132 kV single circuit lines emanate for Hapur, Naglikithore, Jahangirabad, and Gajraula. The industrial town of Gajraula has a 132 kV existing sub-station. There are two 132 kV, single circuit transmission lines emanating from Gajraula, one towards Simbhaoli and the other towards Moradabad. Normally, Gajraula gets its power supply from Simbhaoli, and only in the case of some fault on the Simbhaoli–Gajraula 132 kV section, power is supplied from Moradabad.

At the Gajraula 132 kV sub-station, six 33 kV feeders emanate towards the following load centres:

- the industrial estate;
- Hasanpur;
- Fazalpur;
- Mandi Dhanaura;
- Rajabpur; and
- other industries.

At the Gajraula sub-station, there are four transformers, two at the 132/33 kV level of 40 MVA and 20 MVA capacity each, and two at the 33/11 kV level of 5 MVA capacity each. Power from these transformers is fed into the sub-transmission and distribution system for feeding to the load centres. The total load of Gajraula is about 50 MVa, and in order to meet the growing load demands and improving the quality of power, UPSEB has initiated work for strengthening the transmission system by constructing another 132 kV S/C line from Simbhaoli to Gajraula. These are likely to be completed by 1996/97 Figure 1 shows a single-line diagram of existing transmission systems in the Simbhaoli-Gajraula area.

T & D Options Available for Evacuating 20 MW Cogen Plant Output

The two available options include. Alternative I – sell the entire output (20 MW) directly to industrial consumers at Gajraula by means of a dedicated feeder, taking off from Simbhaoli power stations to Gajraula, and Alternative II – sell the cogenerated power to industrial consumers by using the UPSEB grid, i.e., wheeling the cogen power through UPSEB grid. The pros and cons of the above two options are discussed below.

Alternative I

For meeting the load demands of the Gajraula industrial area, it is not possible to transmit this power at 33 kV as the distance involved is 30 km, which is more than the per-

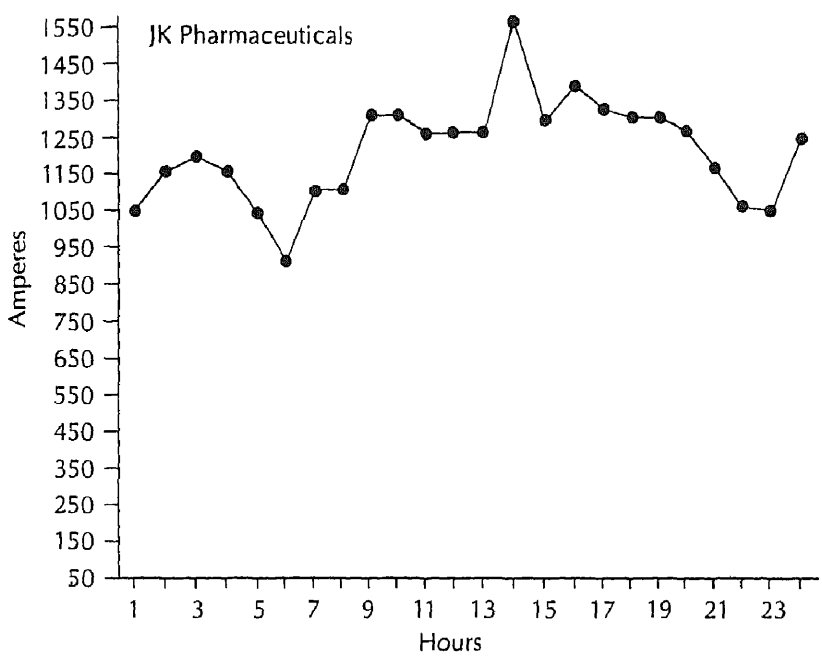


Figure 1. *Existing transmission systems in the Simbhaoli–Gajraula area*

missible limit. A 66 kV transmission is not feasible as the 66 kV voltage level is not available both at Simbhaoli and Gajraula. Moreover, a minimum of two 66 kV single circuits would be necessary to supply 20 MW power to industries in the Gajraula area.

In view of the above, the only option available for meeting the industrial load demand in the Gajraula area is to construct a dedicated 132 kV single circuit feeder with a *Panther*-conductor to Gajraula costing about Rs 555 lakhs. However, the availability of UPSEB grid supply has to be ensured in case of any fault on the dedicated 132 kV single circuit line from the Simbhaoli cogen plant to Gajraula.

Alternative II

As discussed earlier, UPSEB is constructing a new 132 kV S/C line from their 220 kV Simbhaoli grid sub-station to the Gajraula 132 kV sub-station, and is likely to be ready when the Simbhaoli cogen plant is commissioned. It is, therefore, felt that the possibility of exporting cogen power from Simbhaoli to Gajraula over this new additional 132 kV line should be explored with UPSEB before the construction of a dedicated 132 kV line (Alternative I) costing about Rs 555 lakhs is thought of.

It may be mentioned that the policy governing the charges regarding wheeling, banking, etc., have not yet been finalized by the UP state government. One of the proposals that have been mooted recently on this matter contain the salient points outlined below.

1. The quantity of energy specified by the developer to be wheeled out of the energy supplied at the Board's sub-station is to be reduced by 12.5% as wheeling charges to arrive at the energy received at the destination unit after wheeling.
2. Although energy cannot be stored in the Board's grid, keeping in line with government policy, a provision has been made for banking. The energy specified by the developer for banking is to be reduced by 12.5% as banking charges to arrive at such energy to be returned to the developer.

It can be seen that these two points do not cover the case when the developer wants to make use of the T & D facilities of UPSEB for supplying its entire power output directly to industrial consumers at Gajraula. Therefore, a specific decision in regard to the advisability of constructing a dedicated 132 kV line from the Simbhaoli cogen plant site to Gajraula vis-à-vis the 'wheeling' alternative cannot be taken until the UP government spells out clearly its policy in this regard.

Step-up Sub-station at Simbhaoli and Step-down Sub-station at Gajraula

For both the options of supplying power to Gajraula discussed above, provision has to be made for setting up a 6.6 kV/132 kV step-up station at the Simbhaoli cogen plant site. In the case of Alternative 1, the provision for step-down arrangements at the Gajraula, end has also to be made.

Detailed cost estimates of the step-up station at Simbhaoli, the step-down station at Gajraula, and the 30 km long, 132 kV single circuit line from Simbhaoli to Gajraula is given in Annexures 1, 2, and 3 The overall costs of these three are given in Table 3

Cost of Power Transmission

Alternative I

I Assumptions

- Rate of interest = 18%
- Operation and maintenance (O & M) and establishment = three per cent of capital cost
- Life of transmission equipment = 35 years

Table 3

Overall costs of the essential provisions

Provision	Estimated cost (Rs in lakhs)
The 6 6 kV/132 kV, 2 × 12 5 MVA, step-up sub-station at Simbhaoli[a]	380
The 132/33 kV, 2 × 12 5 MVA, step-down sub-stations at Gajraula	285
The 30 km long 132 kV S/C line with a *Panther* conductor	270

[a] The estimated cost of a set-up sub-station at Simbhaoli, i e , Rs 380 lakhs, would be common to both the alternatives discussed above

2. Capital cost of transmission and step down

- Equipment = Rs 5.50 crores
- Annual O & M and establishment charges @ 3% = 0.165 crores of capital cost.
- Annual overall charges = Rs (5.50 + 0.165 × 5.5386) × 0.1806 crores
  = Rs (5.50 + 0.914) × 0.1806
  = Rs 6.414 × 0.1806
  = Rs 1.1584 crores

Alternative II

- Cogen power generated = 20 MW
- Load factor of the system = 60%
- Annual energy generated = 20 × 8760 × 0.6 = 105 million units at the cogen plant
- Wheeling charges @ 12.5% of energy generated by the cogen plant = 13.1 million units
- Assuming overall average cost of energy for UP = Rs 1.23 (data for 1994/95 taken from the *Annual Review* of the Planning Commission)
- Total annual charges = 13.1 × 1.23 million = Rs 1.6162 crores.

However, this economic comparison of the two alternatives is just hypothetical in view of the non-finalization of a policy by the UP government/UPSEB with regard to the wheeling of power by private producers over their grid. Technically, the alternative of supplying cogen power to the UPSEB grid is preferable, as it would provide the requisite stability to the cogen plant.

Conclusion

The main points that emerge from the study are listed below.

1. The Gajraula industrial area, only 30 km away from Simbhaoli, offers an ideal load centre for the utilization of 20 MW power from the Simbhaoli cogen plant.
2. The industrial consumers at Gajraula expressed their dis-satisfaction with the poor quality of UPSEB power supply (average duration of interruptions is about 30–40 hours/month). Discussions with the consumers indicated that they would welcome more dependable power supply even at a somewhat higher price.
3. For transmitting the Simbhaoli cogen power to Gajraula, 6.6 kV/132 kV step-up arrangements have to be made at Simbhaoli (estimated cost: Rs 380 lakhs)
4. UPSEB's existing 132 kV S/C line from Simbhaoli 220 kV grid sub-station to Gajraula is fully loaded and does not have spare capacity available for evacuating the additional 20 MW cogen power from Simbhaoli. Therefore, for this purpose, one alternative would be to build a 30 km long 132 kV S/C line over this section and construct a 132/33 kV step-down sub-station at Gajraula (estimated costs: Rs 555 lakhs).
5. As an alternative to the above option of constructing a dedicated 132 kV system, the feasibility of making use of the second Simbhaoli–Gajraula 132 kV line being built by UPSEB (scheduled for completion in 1996/97) could be discussed. However, it may be mentioned that UPSEB/UP government have yet to finalize their policy with

regard to the wheeling of power by private power producers over their grid. Unless details of the wheeling charges to be levied by UPSEB are known, it would not be possible to make an economic evaluation of the wheeling option vis-à-vis the dedicated 132 kV line option.

Annexure I

Estimate for 6.6 kV/132 kV, 2 × 12.5 MVa step-up sub-station at Simbhaoli

Sl no	Description	Unit rate (in lakhs)	Quantity	Total amount (Rs in lakhs)
1	6 6/132 kV, 12 5 MVA power transmission with OLTC[a]	60 0	2	120 00
	6 6/400 V, 5 MVa transformer (including the cost of 400 V switchgear & associated equipment)	15 0	1	15.00
2	6 6 kV SF_6 breakers	3 00	3	9 00
3	132 kV SF_6 breaker	9 00	5	45 00
4	All switchgear other than CBs[b] (66 kV)			
	66 kV CT[c]	0 30	6	1 80
	Control and relay panel	0 75	2	1 50
	66 kV PT[d]	0 30	3	0.90
	66 kV LAs[e]	0 20	3	0 60
	66 kV isolators	0 25	7	1 75
5	All switchgear other than CBs (132 kV)			
	132 kV CT	1 30	6	7 80
	Control and relay panel	1 50	3	4 50
	132 kV PT	1 20	3	3.60
	132 kV LAs	0 55	3	1 65
	Station auxiliary transmission and AC distribution box	3 00	1	2 00
	132 kV isolators	2 00	9	18 00
		0 60	9	5 40
6	110 V battery with charger	3 50	1	3 50
7	Structure for sub-station	3 00	LS	3 00
8	Control cables	0 30	LS	0 30
9	Foundation for sub-station equipment	3 00	LS	3 00
10	Miscellaneous items (bus connectors, accessories, grounding shielding, fire fighting equipment, sub-station lighting, earthing, etc	5 00	1	5 00
11	Sub-total	—	—	253 30
12	Erection and commissioning 1 to 8 @ 10%	—	—	24 53
13	Overheads on 1 to 8 @ 17%			
	Contingencies (3%)	—	—	7 36
	Transportation (2%)	—	—	4 91
	Vehicle (T & P)[f] (2%)	—	—	4.91
	General establishment charges (10%)	—	—	24 53
	Sub-total	—	—	319.54
14	Civil works, control room, quarters, etc	—	—	60 00
15	Total	—	—	379 54 (say 380)

[a] on-line tap changes, [b] curcuit breakers, [c] current transformer, [d] potential transformer, [e] lighting arrestors, [f] tools and plants

Annexure II

Estimate for the 132 kV/33 kV step-down station at the UPSEB grid sub-station at Gajraula

Sl no	Description	Unit rate (in lakhs)	Quantity	Amount (Rs in lakhs)
1	132/33 kV, 12 5 MVA power transmission with OLTC[a]	60 0	2	120 00
2	132 kV SF6 breaker	9 00	4	36 00
3	All switchgear other than CBs[b] (33 kV)			
	33 kV CT[c]	0 30	4	1 20
	Control and relay panel	0 75	1	0 75
	PT[d]	0 35	2	0 70
	LAs[e]	0 25	2	0 50
	Isolators	0 35	5	1 75
4	All switchgear other than CB			
	132 kV CT	1 30	6	7 80
	132 kV PT	1 50	3	4 50
	Control and relay panel	2 00	2	4 00
	132 kV isolators	2 00	6	12 00
	LAs	0 55	3	1 65
5	Structure for sub-station	1 50	LS	1 50
6	Control cables	0 10	LS	0 10
7	33 kV SF_6 breaker	3 12	6	18.72
8	Power cable 11 kV, 3 core 240 mm^2 XLPE cable for 11 kV breakers, 100 metres/CB	11 00	0 1	1 10
9	Foundation for equipment	0 50	LS	0 50
10	Sub-total	—	—	224 30
11	Erection and commissioning on 1 to 8 @ 10%	—	—	23 43
12	Overheads on 1 to 8 @ 17%			
	Contingencies (3%)	—	—	6 73
	Transportation (2%)	—	—	4 49
	Vehicle (T & P)[f] (2%)	—	—	4 49
	General establishment charges (10%)	—	—	22 43
13	Total	—	—	284 87

[a] on-line tap changes, [b] circuit breakers; [c] current transformer, [d] potential transformer, [e] lighting arrestors, [f] tools and plants

Annexure III

Estimate for erection of the 132 kV S/C line per km with a Panther conductor (130 mm²)

Sl no.	Description	Unit rate (in lakhs)	Quantity	Total amount (Rs in lakhs)
1.	132 kV S/C galvanized steel structure self-supporting tower (nos)	0 800	4 0	3.20
2.	*Panther* ACSR conductor (130 mm^2, km)	0.700	3.1	2.17
3	Insulators (nos/km) suspension/ strain sets	0.040	15	0 60
4	Earthwire (km)	0 160	1 0	0 16
5	Hardware and accessories for conductor (nos)	0.050	12	0 60
6	Hardwares and accessories for earthwire (lumpsum)	0 060	LS	0.06
7	Sub-total	—	—	6 79
8.	Erection and commissioning on 1 to 6 @ 10%	—	—	0 70
	Overheads on 1 to 6 @ 17%			
	Contingencies (3%)	—	—	0 20
	Transportation (2%)			0.14
	Vehicle (T & P) (2%)			0.14
	General establishment charges (10%)			0 70
9	Total			8 67 (say 9)

High-pressure Boilers for Bagasse-based Cogeneration at EID Parry (I)

C V Krishnan,[1] P Ram Babu

Introduction

The sugar industry in India is presently undergoing major technological changes. There are two significant changes that have had a major influence on the operation of the sugar plant – the employment of high-pressure boilers and the reduction of the process steam consumption. Both these changes have helped sugar plants make a significant contribution to cogeneration. The energy crisis and the need to improve energy efficiency have made sugar plant designers look critically at the fuel value of bagasse. High-pressure boilers have demonstrated how additional exportable power could be effectively generated in sugar plants. The high-pressure steam technology, being different from what the sugar plant designers and operators have been used to, needs special consideration during the stages of design, manufacture, and commissioning. Realizing the potential of bagasse-based cogeneration, EID Parry are currently installing a 24.5 MW bagasse-based cogeneration plant in their sugar factory at Nellikuppam in Tamil Nadu. This paper presents an overview of this project and the high-pressure boilers being installed there.

EID Parry (India) Ltd: Background

EID Parry (India) Ltd was established in 1788 and is more than 200 years old, discharging its responsibilities to society with a strong commitment to ethical values and beliefs. The history of EID Parry is a saga of growth and dynamism. It is, today, engaged in a wide range of diversified activities – in the manufacture and marketing of fertilizers, seeds, plant protection chemicals, sugar, industrial alcohol, sanitaryware, and electronic goods. The sugar factory owned by the company at Nellikuppam in Tamil Nadu has a

[1] EID Parry (India) Ltd, Dare House, Post Box No. 12, Chennai, India.

chequered history and the distinction of being one of the oldest sugar plants in the country.

Plant Operation: Existing Scenario

This plant has a present crushing capacity of 5000 tonnes of cane (tcd) per day and operates on an average of 205 days a year. The process steam consumption is around 55% on the cane crushed and the plant's live steam cycle is at 15 ata and 240 °C. The sugar plant operates with six mills and a shredder. Two of the mills are driven by DC motors while the rest of the mills and the shredder are driven by steam turbines operating with an inlet steam parameter of 13 ata and 240 °C. The steam generation capacity of the plant from a battery of five boilers is 145 tonnes per hour (tph). There are three back-pressure turbogenerator sets generating an aggregate electrical capacity of 6 MW. The power generated is wholly consumed by the sugar plant and the distillery, and there is no surplus power available for export.

Plant Operation: Future Scenario

EID Parry has embarked upon a programme of modernization and energy conservation in this sugar plant. This modernization programme is well under way. Under it, the balance of the mill and shredder drives will be converted to DC/hydraulic drives and AC drives respectively, while the crushing capacity of the plant will be enhanced to 5200 tcd and the process steam consumption brought down. EID Parry has also taken up the implementation of cogeneration under this programme.

Steam Generation Scenario in Indian Sugar Industries

A cane sugar plant is generally self-reliant in power and bagasse (the fuel needed for the generation of steam and power). Till the last decade, the boiler which supplies the vital inputs of steam and power to a sugar plant did not attract much attention. Typically, the mills employed low-pressure boilers operating at 14 or 21 kg/cm^2 with superheater temperatures going up to 350 °C. This steam was expended in back-pressure turbo-alternators to produce the plant's requirement of power, and the back-pressure steam at 0.8 kg/cm^2 was used to meet the process requirements. In the last decade, there has been a progressive increase in the boiler-operating pressures in the sugar mills. In the 80s, the sugar plant standard specifications recommended boilers with an operating pressure of 32 kg/cm^2(g) with the superheater outlet temperature of 380 °C. In the late 1980s, some sugar mills opted for boilers operating at 42 kg/cm^2(g) with 400 °C superheater outlet temperatures. The basic reason for such upgradation has been the improvements made in the process side to bring down the steam consumption from the then prevailing figure of around 60%. Efforts in this direction got a major thrust because of the government policy for incentive which demands that the total steam consumption be brought down to less than 50% on cane. This technological change resulted in the mills saving bagasse – the excellent renewable energy source. This step of adopting high-pressure boiler technology opened up interesting new vistas like cogeneration and power export or bagasse saving for paper production.

Developments in Cogeneration in India

Cogeneration has been a subject of interest to the Indian industry and specifically to the Government of India. This interest is born out of the fact that sugar plant cogeneration holds the promise of narrowing the ever-widening gap between power supply and demand at a low incremental cost, and with a short gestation period. A few points which give a boost to cogeneration are listed below.

- The confidence among the industry and operators in the use of high-pressure boilers.
- The enormous saving in bagasse consequent to reduction of steam consumption.
- The emphasis on reduction of greenhouse gas emissions.
- The possibility of increased revenue to sugar mills.

The Indian sugar industry's interest on cogeneration was kindled by the encouragement and financial incentives offered by the Government of India, and the willingness on the part of the state electricity boards (SEBs) to purchase this power at reasonable tariffs. Many sugar mills in India are, today, looking at cogeneration with much more seriousness, and a few mills have gone ahead in implementing cogeneration. EID Parry is one such company where the cogeneration project is in an advanced stage of implementation.

The Cogeneration Project at EID Parry: an Overview

The cogeneration project at EID Parry will be mainly based on bagasse as the fuel, with the boilers also designed to operate on Neyvelli lignite. There will be two boilers, each with a capacity of 70 tph with outlet steam parameters at 67 ata and 485 °C. There will be a single extraction-cum-condensing turbogenerator, with a nominal capacity of 24.5 MW under the extraction-cum-condensing mode. The cogeneration cycle is designed with a high-pressure feedwater heater, heating the boiler feedwater from 105 to 140 °C. The plant is designed with all the auxiliaries and sub-systems required for the efficient operation of the plant. During the cane-crushing season, the gross power generation will be 24.5 MW. It is also planned to operate the cogeneration plant during the off-season, either with excess bagasse generated in the plant and purchased bagasse from nearby sugar mills, or with other biomass fuels like cane trash, rice husk, or with lignite. With an adequate quantity of biomass fuel available, the operation of the plant for a period of more than 270 days is planned. Under the off-season operation, the plant will be exporting a net output of about 22 MW to the Tamil Nadu State Electricity Board (TNSEB) grid. The total project cost is estimated to be Rs 6.8 crores. The project is expected to be commissioned during August/September 1996.

High-pressure Boilers at the Project

Basic Design and Sizing

The cogeneration plant at EID Parry will have two boilers each with 70 tph capacity with the feedwater inlet temperature of 105 °C. With the feedwater temperature raised to 140 °C in a high-pressure feedwater heater, these boilers are capable of giving an output

of 73.5 tph each. The steam parameters at the boiler outlet will be 67 ata and 485 °C with the tolerance on the superheat temperature at ± 5 °C. When EID Parry took up the plant design, there were two important points which confronted the decision makers. One was the selection of a single boiler *versus* two boilers, and the other was the selection of the operating parameters. These two points were deliberated in detail and EID Parry took a decision of going in for two boilers knowing fully well the slightly extra cost involved. The deliberations on the question of selecting the single boiler *versus* two boilers, specifically in the Indian sugar industry, will continue forever. However, EID Parry's decision to go in for two boilers was mainly due to the slight, additional flexibility the two-boiler configuration offers in sugar plant operation.

With regard to the cycle parameters, detailed analyses have been carried out, and the outcome of such analyses indicate that for the capacity of the boilers planned, the additional benefits of extra power generation with higher cycle pressure and temperatures are not commensurate with the additional investment involved. Also, it was decided that with the present level of operation in the sugar industry, and with the stringent requirement in the feedwater chemistry, it is better to limit the parameters to 67 ata and 480 °C. It is also worth mentioning that these are the widely used parameters in the sugar industry worldwide.

Design Considerations

The boilers are of the bidrum design, and are top-supported with a balanced draft operation. The boiler design adopts membrane wall construction, eliminating the use of large quantities of refractory. This design affords better control over the excess air operation of the boiler. The evaporative sections of the boiler are constituted by the furnace and a large boiler bank area. An adequately designed economizer recovers a substantial part of the heat from the flue gases, making up most of the sensible heat addition requirements. The boiler is provided with an air heater which recovers further heat energy from the flue gases and ensures that the flue gases leave the boiler at 160 °C. The boiler is designed with two stages of superheaters. One section is a convection section and the other a radiation section. The surface areas of the radiant and convective sections are proportioned to give an almost flat characteristic in the operating range. In addition, there is an interstage desuperheater which controls the outlet steam temperature well within ± 5 degrees of the rated temperature.

The boiler is designed for outdoor operation and is top-supported on steel structurals. Adequate access stairways and platforms are provided for the easy operation and maintenance of the boiler. Operating on bagasse, the boiler efficiency will be 69.4% on the gross calorific value of 50% moisture bagasse.

Fuel Firing System

The boiler is primarily designed for burning bagasse as the main fuel. The combustion system incorporates a travelling grate stoker, pneumatic distributors, a bagasse storage silo with extraction feeders, and screw conveyors. The bagasse silos are designed for storing a 15-minute requirement of bagasse at a mechanically controlled rate (MCR) operation. There will be four pneumatic distributors, distributing the bagasse onto the travelling grate. This firing system is also capable of handling other biomass fuels such as cane trash, rice husk, and groundnut shells.

In order to ensure that the operation of the plant is continuous, which will result in uninterrupted power supply to the grid, lignite from the nearby Neyvelli mines has been thought of as an alternate/supplementary fuel. Under situations where there is a shortage of biomass fuels, the provision of the lignite firing system will ensure that the agreed quantum of power will still be exported to the grid. Even though the boiler is presently provided with lignite feeders and distributors, the complete lignite handling system and bunkers will be added shortly.

Environmental Considerations

Keeping in mind the environmental considerations, and in line with the values and beliefs the company cherishes, electrostatic precipitators are being installed as the flue gas cleaning system, even though installation of this system substantially increases the capital investment. Each boiler is designed with two induced draft fans, two forced draft fans, and one overfire air fan. Considering the possibility of using lignite as a fuel, and based on the possible sulphur dioxide emissions under the conditions, the chimney has been designed for a height of 92 m. There will be a single chimney catering to the requirements of both boilers.

Instrumentation and Control

Considering the safety and operational efficiency of the plant, EID Parry has installed a state-of-the-art instrumentation system with distributed controls.

Feedwater Management

An elaborate feedwater management system is planned as the boilers will be using condensates from the sugar plant. The sugar plant supplies two types of condensates: one is the condensate from the turbine exhaust steam supplied to the process and the other is the vapour condensate generated in the process. Almost all the exhaust condensate will be used as boiler feedwater. However, conductivity measurement and the automatic bypass of the condensate to the house condensate tanks is provided to ensure that there is not even the slightest chance of contamination of the exhaust condensate. The exhaust condensate is not adequate for the boiler plant operation, and hence some amount of vapour condensate mainly from the point of view of energy conservation is requires. Since the possibility of the contamination of the vapour condensate is more likely, in addition to the instrumentation and control provided for the conductivity measurement and the automatic by-pass of the condensate to the drains, a system of batch tanks and testing of each batch of boiler feed for its fitness, is provided. In the case of continued contamination of vapour condensate, it is planned to use demineralized (DM) water as make-up. A DM water plant, with two 920 streams each with a capacity of 20 tph, is being installed to meet the make-up water requirement.

Manpower Training

Considering the fact that the high-pressure boilers are different from the low-pressure boilers which the boiler operators are accustomed to, an elaborate training, in addition to recruitment of experienced engineers and supervisors, is planned.

Layout Considerations

One of the most important points in the design of the cogeneration plant, specifically an operating plant, is the location of the cogeneration plant within the sugar plant premises. Considering the fact that the plant will be commissioned during the middle of a season, precautions have been taken to locate the plant in such a way that its construction or commissioning does not interfere with the sugar plant operation. It is proposed to retain the existing stream and power system of the sugar plant, till such time as the cogeneration plant stabilizes.

Conclusion

With the need to conserve energy and the thrust given to renewable energy sources, sugar plants have the greatest potential to contribute to the country's power grid. This has made the introduction of high-pressure boilers in the sugar industry imperative. EID Parry's high-pressure boiler will go into operation during the third quarter of this year. A good feedwater management system and a reliable instrumentation and control system are required for the safe and efficient operation of these boilers. Having commissioned many super thermal power stations with much higher boiler-operating pressures, Indian engineers and technologies have the capability to build and operate the high-pressure boilers in the sugar industry.

Industrial Negotiations with Regard to Setting up a Cogeneration Plant: the Simbhaoli Experience

Satwant Singh[1]

Background

Bagasse-based cogeneration for power export to the grid has long been a subject of discussion between the Indian Sugar Mills Association (ISMA) and the Government of India. In a review of the country's non-conventional energy policy, the Ministry of Non-conventional Energy Sources (MNES) – then called the Department of Non-conventional Energy Sources – had considered bagasse-based cogeneration of power as one of the major options. Consequently, a number of agencies in the private and public sectors had shown a keen interest in it.

SSML had initiated discussions on cogeneration through ISMA with MNES, and its representative was placed on one of the sub-committees for submitting recommendations to the Government of India for setting up cogeneration projects. The progress, however, has been very slow, as, at that time, discussions only centered around deciding how sugar mills could cogenerate, what type of equipment should be permitted, and what concessions should be allowed. A controversial issue then raised by the Indian manufacturers of turbines and boilers was that no imports should be allowed and only indigenously made equipment be used in such projects. The stand that Simbhaoli took, however, was different – while we were willing to incur the costs, we wanted the best available equipment in the world market. This was eight years ago. The government agencies were then told that cogeneration in sugar mills was not new. Every sugar mill has been cogenerating for its own use from the very beginning. They, however, did not generate more, as there was no market for the surplus power. The technology for bagasse cogeneration is well known and commercially practised in several countries –

[1] The Simbhaoli Sugar Mills Ltd, (SSML), 802–803 Surya Kiran Building, 19, Kasturba Gandhi Marg, New Delhi - 110 001, India

Australia, Cuba, the Dominican Republic, Mauritius, Reunion (France), and the US (Hawaii) for example. The gestation period for such projects is less than that for conventional thermal or hydro power plants. In India, given adequate market opportunities for power sales, bagasse cogeneration projects appear as attractive investment options, capable of adding to the utility's supply capability while reducing reliance on scarce public funds. For sugar mills, bagasse cogeneration projects could result in added income from electricity or surplus bagasse sales and lower production costs in downstream mill activities.

Major Constraints

Despite these potentially significant benefits to the economy and the proven success in other countries, a bagasse cogeneration project selling surplus power to the grid is still to be realized in India. There are several reasons for this.

First, there is no clear-cut government policy on cogeneration of power for export. Although the Electricity Supply Act (1948) has been amended, it has been done in a half-hearted manner and needs further revision in order to direct the state electricity boards (SEBs) to follow a uniform long-term policy.

The Uttar Fradesh SEB (UPSEB), and, for that matter, all the SEBs, consider sugar mills' cogeneration as an encroachment on their sphere of activity. At one stage, UPSEB had categorically stated that they had surplus power and that, therefore, the sugar mills in the state should concentrate on manufacturing sugar and not get involved in power generation.

Another reason has been the lack of confidence on the part of sugar technologists in handling the condensate problem in high pressure boilers. With appropriate investment, an existing sugar mill should normally be able to export about 40 kWh of electricity per tonne of cane processed. In a maximum electricity configuration, the cogeneration of electrical energy incidental to the process steam flow is augmented by electrical energy obtained from the steam generated by burning all the excess bagasse.

The Simbhaoli Cogeneration Project: Present Position

At Simbhaoli, the cogeneration of power by the sugar plant for supplying to the grid, as a viable proposition, was considered about a decade before, after the completion of a study by the World Bank on the possibilities of setting up cogeneration plants in sugar units in the state of Maharashtra. A complete techno-economic analysis had been conducted by the Simbhaoli sugar mill at that time on the viability of the cogeneration of power by the sugar plant. All our expansion and modernization plans were targeted for eventual cogeneration for commercial purposes.

At Simbhaoli, implementation of the cogeneration project for generating additional power for export faced certain hurdles.

- The generation of electricity was highly controlled, as the Electricity Supply Act (1948) made it almost impossible for the private entrepreneurs to set up small generation capacities.

- Biomass/bagasse based cogeneration, as a renewal energy source, was not encouraged by the Government of India, as it thought that making paper was the only way of utilizing surplus bagasse.
- Setting up of any plant and machinery in sugar plants was required to be approved by the Directorate of Sugar (Ministry of Food, Government of India), and any deviation in the configurations of key equipment, other than the standards list drawn by the Government, was difficult to pursue.

However, after liberalization, the Government has thrown open electricity and power generation to the private sector and the Electricity Act has been amended. MNES has also become very active in this field and has started encouraging generation of power by using non-conventional and renewable energy sources. Power generation by the sugar mills has proved to be very attractive for MNES due to its enormous potential and lower generation costs. Further, bagasse as a fuel was available in abundance with the sugar plants, who have been traditionally burning it in an inefficient manner. The location of sugar plants in rural areas was also an added advantage.

At Simbhaoli, we initiated our cogeneration project by ordering a 77 tonne capacity boiler of 43 at a pressure and 427 °C temperature from Thermax Babcock and Wilcox Ltd. In addition a 12 MW power turbine of the back-pressure type was ordered from Farmatome-Thermodyn Division of France. This equipment was ordered taking into account the potential of surplus power generation to the extent of 7 MW/hour during the crushing season and also for utilizing part of the power and steam to meet our expanded crushing capacity. At the same time, the company had initiated discussions with UPSEB towards a suitable policy for purchase of power generated by the sugar plants. UPSEB has taken a long time to get convinced about the viability of such generation, and ultimately to the purchase of such power, and finally came out with a power purchase agreement (PPA). This PPA still needs a lot of modifications, but considering the favourable attitude of UPSEB in the entire matter, it is hoped that the changes will come about in due course.

In structuring the proposed project, a conservative approach was taken by the Simbhaoli sugar mill by imposing an internal rate of return of 18% on the total project cost in analysing the project. This requirement is satisfied based on the investment programme of approximately Rs 38 crores in the current phase, and Rs 37 crores in future with the generation for approximately 4800 hours annually. The idea is to go for the electricity maximizing configuration. The total power exported to the grid could be up to 4.24 million MW/hour in the first phase and 7.8 million MW/hour. Based on this, the cost per MW of generation works out to Rs 3.125 crore per MW/hour.

International Negotiations

International interest in bagasse-based cogeneration projects came to the forefront in 1993, when the Union Government opened up the power sector for private entrepreneurs and foreign participants and delegates from various countries visited India. The visit of the US Secretary of Energy, Ms Hazel O'Leary was very important in this context as, with her, a number of industrial corporations from the US also visited India with the intention of forming joint ventures in the areas of power generation, including non-conventional and renewable energy.

The interest was tremendous at that stage. After prolonged discussions, SSML was considered as a potential company for setting up a cogeneration plant, and was one of the two sugar mills to sign a memorandum of understanding (MoU). The concept of carbon credits and the zero impact of bagasse-based generation plants on the environment was also advocated. The proposed project, with its international tie-up is essentially an investment programme to upgrade the sugar plant at Simbhaoli in order to enable the production of electricity and bagasse over and above internal mill requirements. The basic investment in plant would typically involve:

- the addition of a high-pressure boiler of 43 kg/cm2;
- the addition of a topping turbo alternator with an inlet steam pressure of 43 kg/cm^2;
- the installation of a bagasse drying system which uses waste heat from the boiler flue gases;
- the modification of the mill's electrical system to enable interconnection with the UPSEB grid for supply of surplus power; and
- process alteration and new equipment for steam savings.

SSML has taken this opportunity of participating in a joint venture as a vehicle for fast growth in this area on account of the following reasons.

- It can provide technical support with regard to steam generation, management of steam, generation of power, and to interface with the grid.
- It can provide necessary capital as the sugar mill can direct its resources into the expansion and modernization of the sugar mill and other operations.
- The utility companies proposing the joint venture were more experienced in generation and distribution of power.
- The sourcing of the equipment can be much better with an international party as a promoter.

The initial upbeat mood could not be sustained for long, and only committed parties were left in the race as time passed. Corporations from Europe, Australia, etc., had also started showing their interest. In case of Simbhaoli, as against the seven members who originally participated in the US consortium, only two are were left.

International interest in cogeneration projects in India targetted bagasse as fuel for the proposed plant. This led to the following observations.

- These projects, under foreign participation, are to be implemented in a separate company other than the sugar mill and it is important to keep the project cost at a very low level in the initial period and expand gradually over a period of time. The setting up of the project in a separate company is intended to facilitate investments into equity by the international parties. It shall also lead to electricity generation companies being able to avail the five-year tax holiday provided under the Income Tax Act (1961).
- Some generation in the off-season is possible by saving and storing the bagasse. However, this calls for a very effective bagasse storing and management system
- UPSEB has drawn up a standard agreement for all the bagasse-based generators and was not prepared to enter into any agreement other than the one drawn up by them for sugar plants. The standard PPA is valid for five years only.

- The possibility of third-party wheeling is remote, as the sugar plants are generally located in areas far away from the industries and setting up an independent transmission system is not feasible.

Hence, only the alternatives listed below can be considered by cogeneration companies to sell power.

- To sell to UPSEB under the general PPA drafted by it for bagasse-based cogeneration.
- To wheel the power to other factories within the same group.
- To bank the power for off-season use by the sugar plant.
- To invite the power-intensive factories to set up their units adjacent to the sugar plant by ensuring a regular supply of power to them.

Recommendations

From our experience at Simbhaoli, we suggest that international parties must necessarily consider the following issues, while entering into joint ventures with Indian companies for setting up cogeneration power plants.

- Each project under international participation should be implemented as a separate company, and not as part of the sugar mill. It is important to keep the project costs at a very low level in the initial period and expand them gradually over a period of time
- The orders for the plant and machinery must be placed on a global tender basis, so that the best possible terms of supply as well as financing can be obtained.
- The international participant should look into the long-term viability of a cogeneration plant as the demand for power in future shall always exceed the supply. Increase in power supply rates in future shall be high because of the reduced subsidization of power by the Government (the overall tariff will go up). The power department of the state has already taken a decision of not subsidizing the power by UPSEB any further.
- The sugar mill shall be an independent company, and, yet, must have interest in the power company by way of substantial shareholding, as its operations are largely dependent upon the power and steam to be generated at the cogeneration plant. Further, the induction of a cogeneration plant should positively contribute towards the sugar mill's profitability.
- As a test case, international parties can look into the setting up of power-intensive units for consuming the power at the site itself, adjacent to the sugar plant, for maximizing revenue and for hedging against all possible risks.

Wheeling of Power to Industrial Customers in Karnataka

S Chandrasekhar[1]

Banking of Power

This paper deals with the banking and wheeling of power. Banking, in this context, has the same meaning as is prevalent in the financial sector, particularly with regard to savings. Only, here, instead of money, we deal with energy in terms of kilowatt-hours. The guiding principle is also similar to a savings bank account where money saved has to be deposited before it can be drawn; here energy is to deposited before it can be drawn. However, the similarity ends here, as the energy generated by the cogenerator is not banked in the literal sense. In fact, with electricity, production and consumption are simultaneous. What is banked is the avoided energy by the utility which short draws its own resources while consuming the independent power and gives it back at a later time.

Why should one bank with the electricity boards? As in the case of major banks which have a network of branches for servicing their customers, an electricity board is the only agency in the state having a similar network of distribution to, and servicing of, consumers. Hence, any energy transferred has, of necessity, to be only with an electricity board till such time another distribution system comes into this field.

Wheeling of Power

Wheeling of power is the expression used by the electricity board to describe the transfer of electrical energy from the independent generating station to the end user through its system. Even in the case of wheeling, it is not as though the power that is generated by the independent producers is being wheeled. Actually, the power being generated is distributed close to the rural stations where the renewable energy sources are normally located. In fact, it has been my strong contention that the utility cogenerating renewable energy should not be charged any wheeling charges as the electricity board gains that

[1] Bhorukha Power Corporation, Hitananda, Lavelle Road, Bangalore - 560 001, India.

much in saved transmission losses by not having to wheel to remote areas. The cost of wheeling is different from state to state and depends on the respective levels of power generation.

Wheeling of Power in Karnataka

In the case of Karnataka, the following guidelines are in operation. For wind power and mini power idle stations, of less than 1 MW capacity, it is about two per cent of the energy transmitted. For mini hydel stations of capacity less than 3 MW, it is about five per cent of the energy transmitted; for all other stations of capacity of about 10 MW, it is 10% of the energy transmitted. In the case of cogenerating stations using bagasse, it has been fixed at six per cent of the energy transmitted.

What this really means, in real terms, is that if the energy transmitted from the cogen plant is around 50 million units, wheeling charges at six per cent work out to around three million units, and the net energy available for appropriation by the developers is about 50 - 3 = 47 million units. The system, therefore, operates as follows. A cogeneration plant exists, and it has its own switchyard, (166 kV or 110 kV) where there is an export energy metre sealed and monitored by the electricity board. A monthly generation is recorded by the difference in the readings between the first of each month and the first of the previous month. These readings are regarded jointly by the representatives of the generating company and the electricity board, and the actual figure of generation for the month is then intimated to the chief engineer of the electricity board at the headquarters who is in charge of the commercial department. It is then credited to the account of the cogenerator in the banking ledger maintained by the electricity board.

The next step is for the generating company to write a letter to the electricity board for allotment of energy, enclosing a list of allottees together with their meter numbers, division, and sub-division, specifically stating that each of them is to be allotted so many units respectively. The state electricity board makes banking ledger adjustments according to this, the balance on credit at the end of the month, and the total on credit. The new month's allotment then begins and the cycle starts again.

Based on this letter, the electricity board issues an official memorandum to all the allottees, asking its operating and maintenance staff to give this energy to the listed parties. It also clearly states that this energy need not be billed as this is allotted by the energy bank by pumping into the electricity board grid. As stated above, there is a common meter reading on the first of the subsequent month, and, thereafter, the generating station deducts the energy allotted by it, and direct billing is done by the generating company for that quantity which the balance is billed by the electricity board. Thus, there is only one meter and the energy supplied by the independent power generating company is based on the first charge.

These, in short are the salient points of the wheeling arrangement currently prevalent in Karnataka. The state electricity board has agreed to provide banking and wheeling facilities to all the renewable energy schemes, including cogeneration. Wheeling of power, to consumers is subject to system constraint because the transformer may not take the load beyond its capacity, in which case the Board may refuse to buy the power. An attractive option for the consumers is to purchase power partly or wholly from the electricity board and the cogen plant. Wheeling charges applicable to the cogeneration facility is

equal to six per cent of energy transmitted. The cogeneration is also permitted to sell electricity to a third party. In case the cogeneration chooses to sell power to the electricity board, the purchase price will be Rs 2 per kWh and there will be no wheeling charge. The cost of power wheeled to the third party will amount to almost Rs 2.20 per kWh. There is one restriction which states that the wheeling of power is restricted to high tension consumers of 11 kV and above. In case the third party is unable to consume all the wheeled power, an option exists to carry forward the unconsumed energy on a month-to-month basis not beyond a water year depending upon the resevoirs capacity in the hydro plants. The Electricity Board can, however, refuse to do so if the resevoirs are full.

Bagasse-based Cogeneration Options in the Indian Sugar Industry

G C Datta Roy[1]

Introduction

A number of studies have been carried out by several national and international agencies to identify bagasse-based cogeneration investment opportunities and the steps required for commercializing the same in the Indian sugar industry. This author has been involved in cogeneration operations for 25 years and in sugar operation for over 5 years. The experiences and observations recorded during one such study, conducted for the Asian Development Bank in association with a consortium of international consultants, are presented in this paper.

Cogeneration Potential

Possible cogeneration potential in India is set at a figure of 3500 MW, based on a study by the Task Force of the Ministry of Non-conventional Energy Sources (MNES), Government of India. This potential depends upon several variables:

- sustainability of area under cane and cane yield;
- fibre content in cane;
- milling efficiency;
- factory energy efficiency; and
- energy conservation measures including bagasse drying.

Based on the summary assessment of the current operation level and sustainability factors, statewise cogeneration potential has been estimated under two different sets of efficiency condition (Tables 1 and 2).[2]

- 2800 MW at higher efficiency level
- 1400 MW at lower efficiency level

[1] Turner Morrison Limited, 55 Basant Lok, Vasant Vihar, New Delhi - 110 057, India.
[2] ADB (1953).

Table 1[a]

Statewise bagasse cogeneration potential estimates under high-efficiency operating conditions

Operating conditions	Andhra Pradesh	Bihar	Gujarat	Haryana	Karnataka	Maharashtra	Punjab	Tamil Nadu/ Pondicherry	Uttar Pradesh
Cane crushed (tch)	1300	1000	2263	1285	2264	10300	780	3350	9750
Electricity use (MW)	39	30	68	39	68	309	23	101	293
Steam used (tph)	585	450	1018	578	1019	4635	351	1508	4388
BP turbine power generated (MW)	73	56	127	72	127	579	44	188	548
Bagasse content (cane percentage)	32	32	34.5	32	32	34	32	32	33
Bagasse production (tph)	416	320	781	411	724	3502	250	1072	3218
Steam production (tph)	874	672	1640	864	1521	7354	524	2251	6757
Surplus steam (tph)	289	222	621	285	503	2719	173	744	2369
Surplus power estimate									
Condensing turbine power from surplus steam (MW)	72	56	155	71	126	680	43	186	592
Surplus back-pressure (BP) turbine power (MW)	34	26	59	34	59	270	20	88	256
Surplus power (MW)	106	82	215	105	185	950	64	274	848
Total surplus power estimate (approximately, MW)					2800				

Table approach[a]

	Assumptions	Calculations
1 Cane crushed (tch)	—	Input
2 Electricity use (MW)	30 kW/tch	30/1000 * (1)
3 Steam used	0 45 tonnes of steam/tonnes of cane	0 45 * (1)
4. BP turbine power generated (MW)	8 tph steam/ MW	(3)/8
5 Bagasse content (cane percentage)	—	Input
6 Bagasse production (tph)	—	(1) * (5)
7 Steam production (tph)	2 1 tonnes of steam/tonnes of bagasse	2 1 * (6)
8. Surplus steam (tph)		(7) – (3)
9 Condensing turbine power from surplus steam (MW)	4 tph steam/MW	(8)/4
10 Surplus BP turbine power (MW)	—	(4) – (2)
11 Surplus power (MW)	(9) + (10)	—

Table 2[a]

Statewise bagasse cogeneration potential estimate under low-efficiency operating conditions

Operating conditions	Andhra Pradesh	Bihar	Gujarat	Haryana	Karnataka	Maharashtra	Punjab	Tamil Nadu/ Pondicherry	Uttar Pradesh
Cane crushed (tch)	1300	1000	2263	1285	2264	10300	780	3350	9750
Electricity used (MW)	39	30	68	39	68	309	23	101	293
Steam used (tph)	715	550	1245	707	1245	5665	429	1843	5363
BP turbine power generated (MW)	72	56	124	71	124	567	43	184	536
Bagasse content (cane percentage)	32	32	34 5	32	32	34	32	32	33
Bagasse production (tph)	416	320	781	411	724	3502	250	1072	3218
Steam production (tph)	803	618	1507	794	1398	6759	482	2069	6210
Surplus steam (tph)	88	68	262	87	153	1094	53	226	847
Surplus power estimate									
Condensing turbine power from surplus steam (MW)	19	14	56	18	33	233	11	48	180
Surplus BP turbine power (MW)	33	25	57	32	57	258	20	84	244
Surplus power (MW)	51	39	112	51	89	490	31	132	424
Total surplus power estimate (approximately, MW)					2800				

Table approach[a]

	Assumptions	Calculations
1 Cane crushed (tch)	—	Input
2 Electricity used (MW)	30 kW/tch	30/1000 * (1)
3 Steam used (tph)	0.55 tonnes of steam/tonnes of cane	0.55 * (1)
4. BP turbine power generated (MW)	10 tph steam/ MW	(3)/10
5 Bagasse content (cane percentage)	—	Input
6 Bagasse production (tph)	—	(1) * (5)
7 Steam production (tph)	1 931 tonnes of steam/tonnes of bagasse	1 93 * (6)
8 Surplus steam (tph)		(7) – (3)
9 Condensing turbine power from surplus steam (MW)	4.7 tph steam/MW	(8)/4 7
10 Surplus BP turbine power (MW)	—	(4) – (2)
11. Surplus power (MW)	(9) + (10)	

However, at present, it is really not important whether it is 1400 MW or 3500 MW or higher. The issue today should really be how quickly each and every factory can realize its cogeneration potential.

Perception of Benefits and Risks

Several factors like perceptions of risk rewards, inadequacy of institutional arrangements, fluctuating fortunes of the industry, technical and infrastructural issues, etc., have been responsible for relatively slow progress so far (though the momentum seems to have picked up a bit in the last two years, due to efforts by MNES). There is a need to further educate all those involved in the sugar industry on the enormous rewards and the various options available for minimizing risks, particularly risks on sugar operation. This would help in the further acceleration of the process.

Benefits

The principal benefits of investment in bagasse-based cogeneration include:

- an improved sugar economy and reduced earning fluctuations;
- low cost/low gestation investments; and
- positive environmental impacts.

Improved Sugar Economy and Reduced Earning Fluctuations

The sugar industry, and, consequently, the farmers involved in sugarcane production, periodically go through deep depression on account of price volatility as a result of agro-climatic conditions and governmental controls worldwide. Variations due to agro-climatic factors are practically beyond control. It is also anticipated that the General Agreement on Tariffs and Trade/World Trade Organization (GATT/WTO) will not have any significant impacts on governmental control over this industry. Thus, one of the ways that the industry can maintain relative stability in the long run is by reducing revenue dependence on sugar. Unfortunately, in India, barring one factory in the South, the revenue from by-products for almost all the factories are less than 10% (Table 3).

In one study carried out by the author in 1995 for two factories in Bihar, it has been estimated that revenue from cogeneration can be close to 40% of the gross revenue (Tables 4 and 5). Thus, even a price variation of 10% in sugar would not have more than a 5% impact overall. This would help in maintaining a positive contribution even during the worst cyclical depression.

Low Cost/low Gestation Investments

Various investment opportunities and risk profiles exist. Table 6 presents some of the options available in a typical case, which has been studied.

Table 3
Revenue from sugar and by-products
(Rs in lakhs/year)

Average revenue sales of sugar	Revenue from sales of by-products	Amount (percentage of total)
9101	244	2.68
9204	499	5 42
9236	342	3.70
10510	398	3.78
9414	193	2 05
NA	NA	—
8962	252	2 81
8592	685	7.97
9105	677	7 43
NA	411	—
9872	NA	—
9009[a]	2239	24 85
10099	28	—
8739	588	6 73
8765	960	10.95
8236	277	3 36
9180	156	1 67
9234	878	9 51

[a] except for this factory for the rest the earnings from by-products are less than 10%
Source NPC (1994)

Even the high cost (low technical risk) option of Rs 3.5 crore/MW compared favourably with normal thermal projects. The project duration can range anything from 10 months to about 24 months depending upon the size and the plant configuration This is again about half the time required for thermal plants. Further, many of the central and state government clearances required for thermal plants are not required here, especially in the cases of investment in an operating sugar plant

Positive Environmental Impacts

CO_2 emissions in a fossil fuel based thermal plant are around 1 kg/kWh (Entec-N Water Group 1995) depending on the carbon content in the fuel. Incremental bagasse consumption for surplus power could be estimated at around 20% of this figure. Thus, a CO_2 saving of 0.8 kg/kWh is achievable. 4.5 million tonnes of CO_2 emissions could be avoided if 2000 MW of cogeneration power operates at a load factor of 80% for 150 days/year. This also offers an economic opportunity for trading in global CO_2 permits, given supporting institutional arrangements.

Table 4
Estimation of cogeneration potential

Total cane crushed (tonnes/year)	875000 + 700000 = 1575000
Bagasse (as percentage of cane)	35
Bagasse production (tonnes/year)	551250
Steam potential @ two times bagasse (tonnes/year)	1102500
Steam requirement @ 50% cane crushed (tonnes/year)	787500
Surplus steam to be put into the condensing turbine (tonnes/year)	31500
Assumptions made for power calculation	
Boiler steam conditions	42 bars 430 °C
Exhaust conditions (bars)	1
Power requirements for factory operation (kWh/tonnes of cane)	35
Steam consumption in BP turbine (kg/kWh)	8
Steam consumption in condensing turbine (kg/kWh)	4.3
Calculation	
Cane crushed (tonnes)	1575000 (a)
Steam required @ 50% of (a) (tonnes)	787500 (b)
Power produced (kWh) from BP turbine @ 8 kg/kWh (b/8)	98437500 (c)
Power required (kWh) (@ 35 kWh/tonnes of cane) (a x 35)	55125000 (d)
Surplus (kWh) from BP turbine (c – d)	43312500 (e)
Steam flow in condensing turbine (tonnes)	315000 (f)
Power produced (kWh) @ 4 3 kg/kWh (f/4.3)	73255800 (g).
Overall surplus (kWh) (e + g)	116568300

Risks

There are, however, certain risks too. These include:

- magnitude of investment;
- risk to sugar manufacturing operations; and
- other technical, commercial, and financial risks.

Magnitude of Investment

Factors like present steam and power generation capacity and surplus, if any, steam pressure and temperature parameters, location of sub-stations, etc., would effect the magnitude of investment in cogeneration. Very low-cost opportunities exist in certain factories where, just by installing a transmission line and a sub-station, surplus power of over 500 kW could be supplied immediately. On the other hand, an investment of Rs 25 crores would be essential for generating surplus power of over 9 MW using high-pressure and high-efficiency technologies.

Risks to Sugar-manufacturing Operations

Huge risks are involved when a topping cycle is used in manufacturing operations. Any disturbance in the topping turbogenerator (TG) sets as a result of grid problems, would

Table 5

Details of costs and contribution

Product involved: sugar	Target	Present	Impact
Cost of production (average; Rs/tonne of sugar)			
Cane	6680	7820	—
Stores	400	400	—
Electricity and fuel	—	50	—
Labour	310	2625	—
Packaging	220	220	—
Others	500	1000	—
Total cost	8110	12115	4005
Realizations			
FS @60% of 12000	7200	7080	—
Levy (40% of 7600; Rs/tonne of sugar)	3040	3040	—
Total	100240	10120	120
Contribution			
Rs/tonne	2130	(–)1995	4125
Rs in crores/year	29.5	(–)2.70	32.20
Molasses			
Molasses production @4.5% cane crushed (tonnes/year)	70875	10485	—
Sales realization (Rs/tonne)	1000	1000	—
Annual contribution (Rs in crores/year)	7	1.05	5.95
Power			
Power sold (crore kWh/year)	11.66	—	—
Realization (Rs/kWh)	2.00	—	—
Annual contribution (Rs in crores/year)	23.00	—	23.00
Total annual contribution (Rs in crores/year)	59.5	(–)1.65	61.15

interrupt manufacturing operations totally. The cost of such interruptions can be extremely high on account of production loss, machine failures, spillage of juice and sugar, and quality degradation.

Similarly, in the event of low frequency (48 cycles/second is not uncommon), many of the critical pumps particularly operating for, and under, vacuum conditions can get deprived. The second problem can occur even when a separate TG set is run in parallel with a TG set supplying power and steam to a sugar factory.

Table 6

Supply to grid and investment

Supply to grid (MW)	0.56	3.54	4.88	7.24	8.81	9.08
Investment (Rs in crores/MW)[a]	0.56	3.43	3.53	2.94	3.36	3.15

[a] includes that for sub-stations and transmission

Other Technical, Commercial, and Financial Risks

The operation of high-pressure boilers often involves technical risks. The maintenance of instruments and control systems is also essential for operating high-pressure systems. Though expertise for 42 kg/cm^2 systems has been developed to some extent, the importance of water purity control is yet to be fully understood. Similarly, boiler manufacturers need to gain more experience in designing high-reliability superheaters for high-temperature sugar boilers. Trained manpower for the maintenance of instruments is also not available and a manufacturer-support service usually depends on the proximity of the factory to big cities.

Other financial and commercial risks occur particularly in respect of recovery of dues, availability of adequate fuels, etc. These have been debated at length in many forums and recently, several initiatives have been taken by the state governments in cooperation with MNES.

Development of Cogeneration Options

Considering the above factors and based on the study of the three factories visited during this, seven study different options were conceptualized (Figures 1–8). These cover low-pressure options under existing conditions, high-pressure options at 42 and 62 kg/cm^2, both simple and topping cycles, parallel and stand-alone operations, and off-seasonal operations in the condensing mode as well. The investments and risk profiles of the various options denoted by a range of 1 to 7 corresponding to Figures 2 to 8 are given in Figure 9.

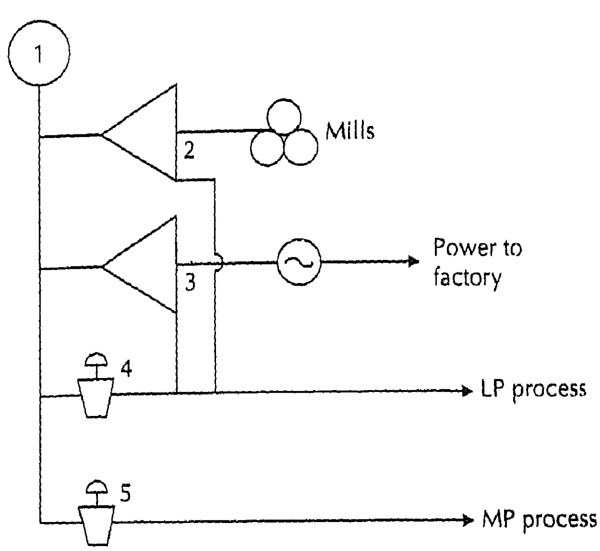


Figure 1. *Present systems; 1: boiler(s); 2: mill turbine/mills; 3: power turbine(s) generator(s); 4: pressure-reducing valve (PRV) for low pressure (LP) process steam; 5: PRV for medium pressure (MP) process steam*

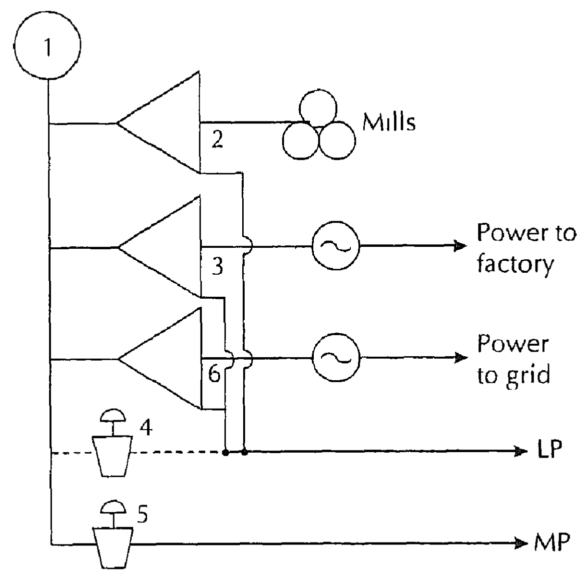


Figure 2. *New BP turbine set to minimize/eliminate PRV use; 1: boiler(s); 2. mill turbine/mills, 3: power turbine(s)/generator(s); 4: PRV for LP process steam; 5· PRV for MP process steam; 6: new BP set to eliminate LP PRV*

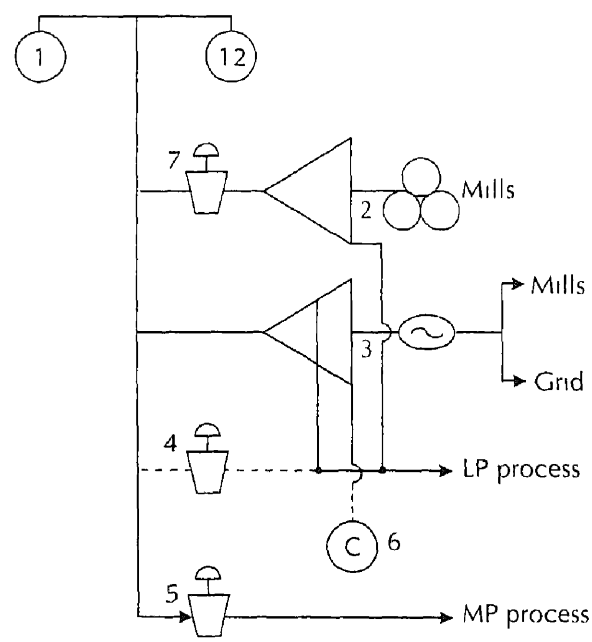


Figure 3. *New extraction condensing (EC) turbine and boiler capacity to burn all bagasse in-season; 1: boiler(s); 1a: additional boile., 2: mill turbine(s)/mills; 3: power turbine(s)/generators EC; 4: PRV for LP process steam; 5· PRV for MP process steam; 6: condenser; 7: PRV for existing LP mill turbine (if new high pressure) mill turbine not installed)*

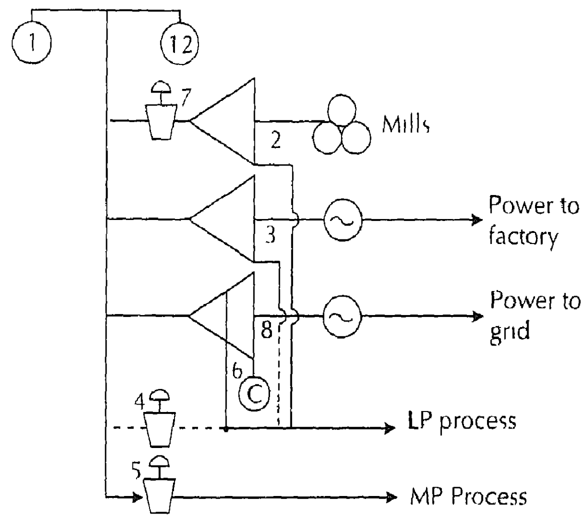


Figure 4. *New BP and EC turbines and boiler capacity to burn all bagasse in season and off-season surplus generation from condensing turbine; 1. boiler(s), 1a. additional boiler, 2: mill turbine(s)/mills; 3: BP power turbine(s)/generators; 4: PRV for LP process steam, 5: PRV for MP process steam; 6: condenser; 7: PRV for existing mill turbine; 8: separate EC TG set for power supply to grid only*

Notes *PRV for LP normally not in circuit steam make up from an EC set; boiler for additional capacity; EC set for grid; LP steam operating in parallel*

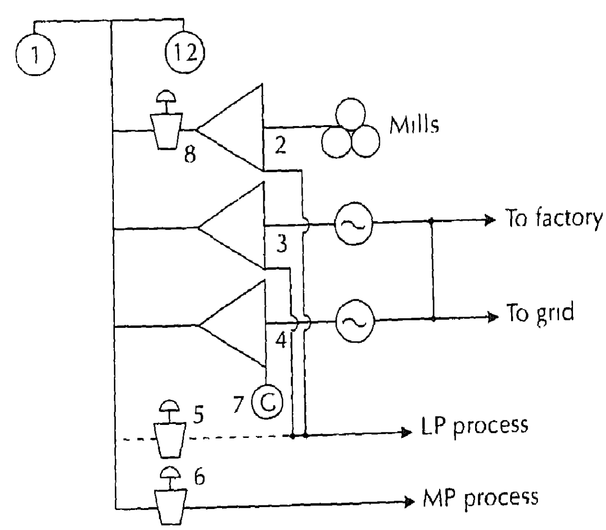


Figure 5. *New BP and straight condensing turbines and boiler capacity to burn all bagasse in season and off-season surplus generation from condensing turbine; 1. boiler(s); 1a: additional boiler; 2: mill turbine(s)/mill(s); 3: power turbine(s) (BP); 4: condensing TG set for power supply to grid only; 5: PRV for LP process steam; 6: PRV for MP process steam; 7: condenser; 8: PRV for mill turbine*

Notes. *PRV for LP normally not in circuit; BP set sized for no flow through PRV for LP (boiler for additional capacity; condensing TG set for grid); Power in parallel; and condensing set stand-alone can be run in off-season*

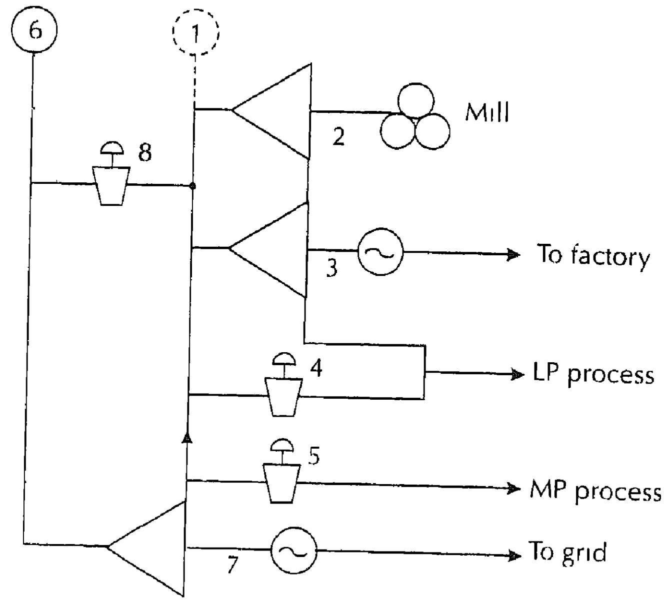


Figure 6. *BP topping system; 1: LP boiler(s); 2: mills/mill turbines; 3: LP power units; 4: LP PRV; 5: MP PRV; 6: HP boiler(s); 7: HP topping turbine; 8: HP PRV*

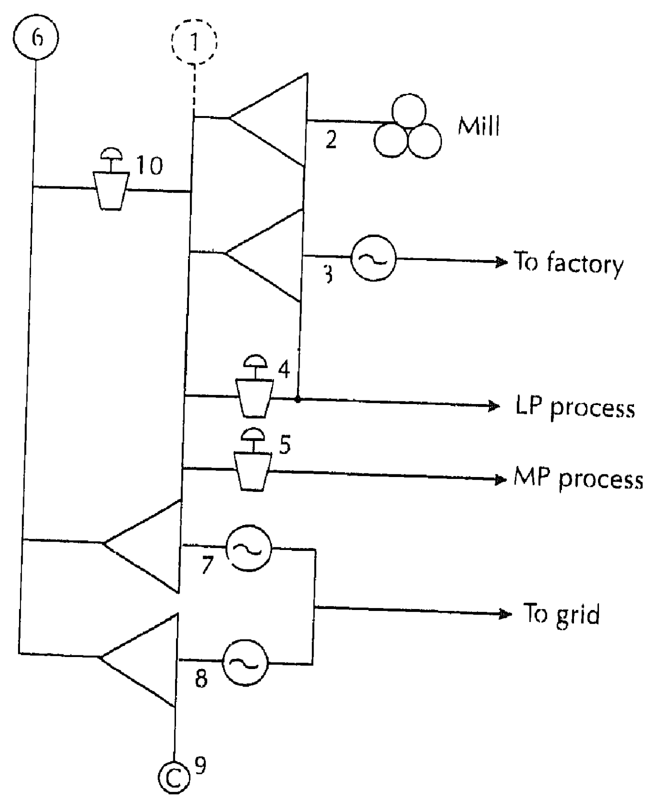


Figure 7. *BP topping system for in-season operations and straight condensing turbine for off-season operations; 1: LP boiler(s); 2: mills/mill turbines; 3: power turbines; 4: LP PRV; 5: MP PRV; 6: HP boiler; 7: HP topping turbine; 8: Condensing unit; 9: condenser; 10: HP PRV*
Note. *6–9: new additions*

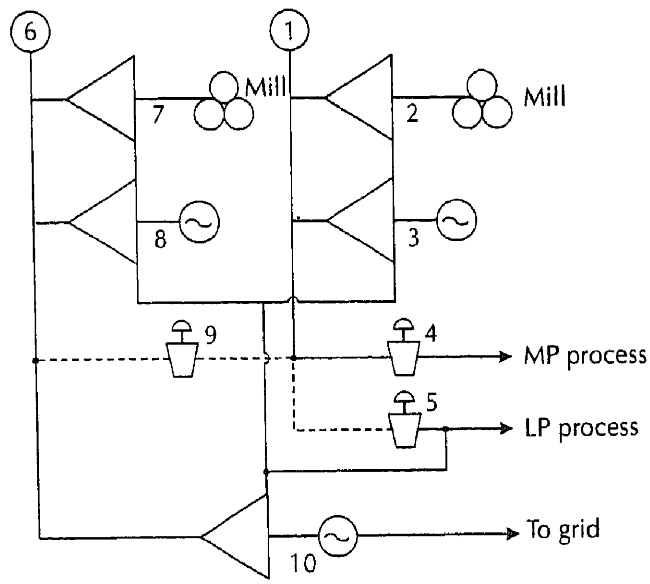


Figure 8. *Retrofit for dual-pressure operating plants; 1: LP boiler(s); 2: LP mill turbines; 3: LP power sets; 4: MP PRV; 5: LP PRV; 6: HP boiler; 7: HP mill turbines; 8: HP power sets; 9: HP/LP boiler interconnecting PRV; 10: retro BP set (BP to match either LP process or LP boiler depending upon flowrate)*

Risk \ Investment	Low	Medium	High
High		6 (Figure 7)	5 (Figure 6)
Medium	7 (Figure 8)	2 (Figure 3) 4 (Figure 5)	3 (Figure 4)
Low	1 (Figure 2)		4 (Figure 5)

Figure 9. *Investment and risk profile of options*

Techno-economic Considerations and the Decision Process

Options are available for every type of risk profile for a particular factory. One can decide to take a small step to start with, go through the learning journey, and decide which big step to take and when. Most of the options are techno-economically feasible, though the relative attractiveness varies. A typical route is illustrated in Figure 10.

Conclusions

The above-mentioned study reveals that cogeneration solutions to suit the need and capacity of every type of sugar operator could be possible. There is, therefore, a need for the development of a marketing strategy by financial institutions to identify various market local constraints, and offer investment packages to suit the needs and risk perceptions of every potential customer. It is also necessary to launch an education programme for creating awareness of the multiple benefits to society from bagasse cogeneration systems. Feasibility of global trading in CO_2 permits could also be explored by governmental and non-governmental institutions.

These steps would supplement the initiatives taken by MNES and the Indian Renewable Energy Development Agency in the last two years, and would help in place a plan to achieve a target of minimum of 2000 MW bagasse-based cogeneration power supply to the grid by the year 2000.

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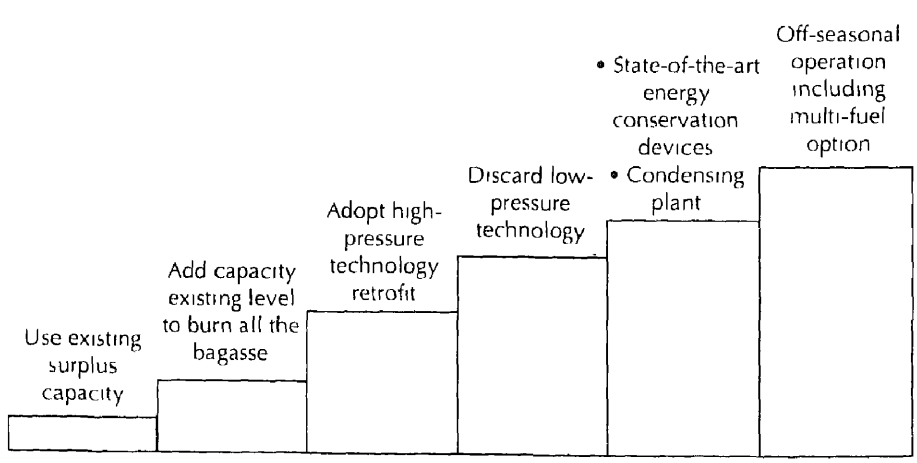


Figure 10. Bagasse-based cogeneration: a travel plan

Session VIII

International Experiences in Cogeneration

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Cogenerated Power Regulations and Tariffs in France[1]

J P Tabet[2]

Transparency 1
The Electric System in France

1. A vertically integrated state-owned utility: Electricité de France (EdF)

   - Power generation: 444 TWh (in 1995) – 79% nuclear; 15% hydro; and 6% coal and heavy fuel oil
   - Power exportation: 73 TWh (16%)

2. Independent producers

   - Power generation: 27 TWh – 25% hydro; 30% coal mines; and 45% self-generation
   - Single-buyer sale to EdF or self-consumption
   - Transport and import/export: EdF monopoly
   - Distribution: conceded by municipalities to EdF (96%) and local utilities (4%)

[1] Reproduced from the presentation made at the Conference, with minor modifications.

[2] TABET, Ademe, Service Economie - Prospective, 27 rue Louis Vicat - 75737 Paris, CEDEX 15, France.

Transparency 2

Cogeneration in France

1. Power capacity: 2200 MW
   - Mainly: back-pressure steam turbines in industry
2. Power generation: 5000 GWh (1.4% of national consumption)
3. Rates of growth (installed power capacities)
   - 1975–1980: weak or negative (fuels prices and nuclear programme)
   - 1991–1993: +50 MW per year
   - 1994: +100 MW
   - 1995: +140 MW
     (European Union: +2000 MW in 1994)
4. Characteristics of recent growth
   - Mainly gas turbines and engines (electric output and tax motives)
   - Based on thermal requirements (regulations motives)
   - Importance of the commercial sector (50% until 1994)

Transparency 3

Independent Producers' Status in France

1. From 1946 (Electricity Nationalization Law)
   - Free private generation for self-consumption
   - No possible sales to other consumers
   - Obligation of purchase by the grid (EdF) under a 8 MW limitation
   - Tariffs of purchase indexed to tariffs of sale (avoided costs formula)
2. From 1980
   - The 8 MW limit is suppressed for power generation from district heating plants
3. From 1995
   - Obligation of purchase restricted to electricity generated: by cogeneration (certificate of agreement is needed); and from renewable energy sources (wind, solar, hydro, biomass), municipal and industrial wastes, and district heating plants

Transparency 4

Cogeneration Certificate of Agreement

1. From 1995, in order to:

   - sell power to the grid; and
   - gain from tax incentives

2. Conditions

   - Global output above 65% (electric + thermal)
   - Heat on power ratio above 0.5
   - Heat production is defined as internally valorized or sold in normal economic conditions

3. The certificate is:

   - issued by local offices of the Ministry of Industry and Energy;
   - subject to inspections by the same; and
   - not needed for previous firmed purchase contracts

Transparency 5

Public Incentives for Cogeneration

1. These incentives were decided in 1991 and 1992.
2. Fiscal policy

   - Exemption on fuel taxes: gas -8% on average; low-sulphur heavy fuel-oil -15% in average
   - Accelerated amortization (one year fiscal mortgage)
   - Exemption of 50% of the professional tax

3. Subsidies

   - 50% grant for engineering feasibility study (managed by Ademe)
   - 10-30% grant on environmental overcosts (managed by the Air Tax Fund)

4. Tariffs

   - Until now based on generation and transmission avoided costs
   - 1996 project: summer incentive tariffs + environmental bonus

Transparency 6

Power Purchase Tariffs by the Grid

1. Without guaranteed power capacity (hydro, wind turbines, etc.)

   - Single-part tariff; remuneration only for generated kWh
   - Two or four seasonal periods, regularity bonus of 20% in winter
   - Average global remuneration in 1994: $6.4 for 100 kWh (hydro) and $5.8 for 100 kWh (wind turbines)

2. With guaranteed power capacity (cogeneration, municipal waste plants, etc.)

   - Double-part tariff; remuneration for guaranteed kW and generated kWh
   - Calculated from sales tariffs (a very long-use option)

     - Abatement from −9% to −17% for guaranteed power part
     - Abatement from −4% to −6% for generation part
     - Generation strongly dependent on hour and season period

   - High penalties in case of power failure: up to $ 1.1 per kWh

Transparency 7

Power Sales Tariffs in France

1. Based on four principles

   - Long-term marginal cost *for the structure* of tariffs
   - Utility (EdF) financial equilibrium *for the level* of tariffs
   - Geographical levelling of tariffs (equity between regions)
   - Two-parts tariffs: *power capacity needs* and *power generation needs*

2. Public tariffs

   - Fixed by a governmental decree (normally once a year, in February or March)
   - Applicable by EdF and other utilities, throughout the country (overseas included)
   - No commercial reductions or bargains
   - State–EdF planning contract: average prices are decreasing by 1.25% each year (in constant money).

3. Three families of tariffs

   - Domestic uses: from 3 to 36 kVA, simple or night and day tariff
   - Commercial uses: from 36 to 250 kVA, with four-hour and season periods
   - Industrial uses: above 250 kW, with four, five, or eight hour and season periods

Transparency 8a

Industrial Power Sales Tariffs

1. Three classes
   - *A* tariffs: between 250 kW and 10 MW
   - *B* tariffs: between 10 MW and 40 MW
   - *C* tariffs: above 40 MW
2. Four versions
   - Very long use: kW is more expensive, kWh is less expensive
   - Long use
   - Average use
   - Short use: kW is less expensive, kWh is more expensive
3. Four types of hours and seasons divisions
   - *Five periods*: Peak, full and empty winter and full and empty summer hours
   - *Eight periods*: same, plus full and empty mid-season and July–August hours
   - *Modulate*: Four *real time* periods: peak, winter, mid-season, and summer
   - *EJP*: One *real time* peak period + three fixed seasonal periods

Transparency 8b

Industrial Power Sales Tariffs

1. Number of hours for each period
   - Peak: between 249 and 396 hours
   - Winter: between 1170 and 1911 hours
   - Mid-season: between 1464 and 3138 hours (if present)
   - Summer: between 3648 and 4056 hours
   - July–August: 1488 hours (if present)
2. A-5 long use tariffs (March 1995, FF 5 = $1)
   - Power capacity part: $95 per kW
   - Peak hours kWh price: $15.4 per 100 kWh
   - Empty summer hours: $2.4 per 100 kWh
3. B-Modulate average use tariffs
   - Power capacity part: $32 per kW
   - Peak hours kWh price: $28.3 per 100 kWh
   - Empty summer hours: $1.9 per 100 kWh

Transparency 9
Power Purchase Tariffs

1. Same complexity, but only one version (very long use)
2. A-5 tariffs (February 1995l; FF 5 = $1)

   - Power capacity part: $127 per kW
   - Peak hours kWh price: $9.5 per 199 kWh
   - Empty summer hours: $2.2 per 100 kWh

3. B-Module tariffs

   - Power capacity part: $99 per kW
   - Peak hours kWh price: $13.7 per 100 kWh
   - Empty summer hours: $1.8 per 100 kWh

4. Average tariffs (including power capacity part)

   - A-8 tariffs, 3750 hours of furniture, $9.7 per 100 kWh
   - B-Modulate, 3750 hours of furniture, $9.0 per 100 kWh
   - B-Modulate, 5088 hours of furniture, $7.8 per 100 kWh

Transparency 10
Projected Improvements of Cogeneration Status

1. Suppression of 8 MW limit (or significant raising)
2. Possibility of direct local power sales by cogenerators
3. Evolution of purchase tariffs fixed for contract duration
4. Revision of avoided costs formula (transmission costs)
5. Revision of power failure penalties calculation
6. New purchase tariffs for cogenerators

   - Interesting if more than 5000 hours of generation (industry)
   - One-part tariff, without seasonal period
   - Weekly programming for guaranteed power

7. Implementation of a cogeneration environmental bonus

Dual Fuel Fired Gas Turbines

T I Mina,[1] G S Robinson, A Seamer

Introduction

This paper describes the necessary systems development and modifications undertaken to supply an European gas turbines (EGT) Typhoon gas turbine to operate on gas fuel, produced by the gasification of wood waste (biomass gas fuel), with a lower calorific value (LCV), in the range of 4.6 to 5 MJ/Nm^3. The systems involved include air bleed, fuel, combustion, and control. All systems have been developed to production standards and meet the requirements for a dual fuel biomass/diesel commercial application.

The gasification process utilizes an air-blown pressurized bed-type gasifier. The air is supplied to the gasifier from the gas turbine compressor via a booster compressor. The air bleed system is designed to supply up to 15% of the total compressor air to the gasification process with minimum disturbance to the combustion system and minimum pressure loss. The biomass fuel is supplied to the gas turbine at a temperature in the range of 300 to 400 °C and a working pressure up to 22 bars. The gas fuel system is designed to supply and control the biomass fuel flow at the above conditions and to compensate for variations in the LCV of the gas. The biomass fuel will not be available until the gasifier has reached steady-state operating conditions and the gas turbine must, therefore, run for a considerable length of time on an alternative fuel, in this case, diesel oil.

The gas turbine combustion system is designed to operate on biomass fuel and diesel oil. It has been developed to enable start-up on the auxiliary fuel and operation around the required engine cycle, including on-load fuel change-over. An imposed restriction on the combustion system design has been to maintain physical interchangeability with the standard conventional Typhoon combustion system. The gas turbine control system has been modified to allow satisfactory interaction with the integrated plant.

EGT, in line with worldwide interest in alternative energy sources, undertook the challenging task of burning a biomass gas fuel (BGF), with an LCV in the range of 4.6 to 5 MJ/Nm^3, as well as diesel oil in an existing EGT gas turbine. The Typhoon engine used as a base for this project is a third generation, industrial, high thermal efficiency gas tur-

[1] European Gas Turbines, P O Box 1, Thorngade House, Lincoln, LN2 5DJ, UK.

bine designed for all power generation duties within the 4 to 5 MW power bracket (Carchedi *et al.* 1988; 1991).

Gas Turbine Operation Requirements

The gas turbine is part of the initial process in the integrated plant operation and, therefore, is required to perform the functions listed below.

- To supply up to 15% of total compressor air to the gasification process. Hence, its starting and acceleration to full-speed no-load (FSNL) is performed utilizing an auxiliary conventional fuel, in this case, diesel oil.
- To maintain on-load operation using the auxiliary fuel until the gasifier reaches steady-state operation.
- To accommodate on-load fuel change from the auxiliary fuel to BGF and sustain commercial output.
- To accommodate on-load fuel change back to the auxiliary fuel.

In the following sections, the paper describes the necessary systems development and modifications to achieve the above requirements.

Air Bleed System

The pressure of the air is increased from compressor delivery pressure of 13–14 bars to a pressure of 22–23 bars using a booster compressor before it is supplied to the gasification process. To minimize the size of the booster compressor and to reduce the effect of the air bleed on the combustion system, the air is bled utilizing the existing 12 equi-spaced secondary steam injection ports positioned on the turbine casing.

The internal diameter of the ports has to be increased from 15.5 to 18.3 mm to maintain the 0.5 bar pressure drop across the air bleed system. To evaluate the effect of a single feed from the manifold to the booster compressor, a calculation was performed and subsequently verified using a computerized fluid dynamic (CFD) analysis package to predict the air flow for each branch, thus, enabling the air bleed ports, pipes, and manifold to be sized. The results of this calculation indicated that, for the configuration chosen, the variation in air flow from one branch to another is within acceptable limits.

The extraction of the equal mass flow of air bleed from each branch should have an equal effect on each combustor. Therefore, the air bleed should not have an impact on the exhaust temperature profile which is used for turbine control. The air bleed branch pipes are designed to support the manifold and to accommodate any differential thermal expansion that may take place between the turbine casing and the manifold.

The full load air fuel ratio (AFR) for the BGF operation is 4.5:1. Therefore, the mass flow rate of the BGF required at this condition is approximately 18% of the total mass flow rate through the turbine, which will result in a raise in compressor delivery pressure and subsequent loss of surge margin. The air bleed required to produce the BGF is approximately 80 to 90% of its mass. Therefore, the air extraction will restore most of the lost surge margin and avoid a costly first-stage turbine nozzles redesign.

To prevent pressure pulses from the reciprocating booster compressor affecting the turbine compressor, a large volume receiver is incorporated in the air bleed extraction line to act as a buffer. Also, to avoid a sudden increase in the turbine compressor pressure, the rate at which the air bleed flow could be reduced is mechanically limited by a control valve. For the same reason, the plant control system monitors the booster compressor speed and will activate an emergency turbine shutdown if a sudden failure of the booster compressor occurs.

The extraction of up to 15% of total compressor air will result in a reduction of the combustion air, combustor cooling air, and turbine cooling air by the same percentage. When the turbine is operating on auxiliary fuel with the air bleed, the turbine inlet temperature must not exceed the rated maximum (TMAX) to maintain a hot component life. Therefore, the turbine maximum output power will be reduced.

In the case of BGF operation, the enthalpy content in the BGF is sufficient to increase the output power above the rated power if the turbine inlet temperature is kept at TMAX. However, as the turbine cooling air has been reduced, it is important to reduce the turbine inlet temperature to that needed for generating the rated power only (TBGF) It is also prudent to limit the turbine inlet temperature to TBGF when operating on auxiliary fuel operation air bleed and accept a further reduction in the power output.

The BGF System

The BGF system is designed to operate within a temperature range of 250 to 425 °C a fuel pressure range of 16.5 to 28 bars, and an LCV range of 4.1 to 8.1 MJ/Nm^3. The system is also designed to supply the necessary primary steam injection flow required during diesel oil operations for NO_x emissions control. The BGF supply temperature, pressure, and LCV may vary independently of turbine load. To control the BGF mass flow rate, it is necessary to map the effective area of the metering valve as the valve angle. The BGF supply pressure, temperature, and pressure drop across the valve are continuously monitored; knowing the BGF LCV and other relevant properties, the turbine control module (TCM) is used to compensate for variations in pressure, temperature, and LCV of the BGF, and supply the turbine with the required BGF flow rate for the given load. The BGF system has been designed for a maximum non-operational pressure of 35 bars.

The BGF may contain contaminates such as tars, that may condense at temperatures below 250 °C. To prevent both contaminate condensation on cold pipes and thermal shock, the BGF pipework upstream of the BGF module is preheated using steam trace heating. An additional preheating of the upstream pipes is achieved using a reverse flow of nitrogen at 400 °C which is introduced prior to connecting the BGF supply. The nitrogen is also used for purging and pressurizing the system to enable the connection of the BGF supply without the loss of gasifier pressure. Within the BGF module, preheating is performed using electrical trace heating.

After the pipework and the BGF module are preheated, the BGF will be admitted to the gas turbine only if its pressure, temperature, and LCV are within acceptable limits. During the operation on the BGF, the TCM will monitor its condition and, if any of its properties exceeds a predetermined limit, a change-over to diesel oil or, in extreme cases, an emergency shutdown will be initiated.

The BGF is potentially explosive and toxic in nature: therefore it is imperative that after a shutdown is initiated, when operating on BGF, the BGF system, turbine, and boiler must be thoroughly purged. A normal shutdown from the BGF is performed by first changing to the diesel oil operation, followed by a shutdown. On changing from BGF to diesel oil operations, the BGF supply is isolated, and a reverse purge of the system upstream of the BGF module is performed using hot nitrogen. Simultaneously, the system downstream of the block valve, including the metering valve is forward purged with steam. If the steam supply fails or is not available, as on an emergency shutdown, hot nitrogen is used to forward purge the system. The forward purge of the BGF system must take place while the turbine is rotating. If the system is forward purged without a positive air flow through the gas turbine, the BGF will collect in the turbine exhaust system and boiler. An additional emergency safety feature is incorporated, which will allow a reverse purging of the system using compressor delivery air, if both the steam and the nitrogen purge systems fail. The reverse purge is achieved by allowing the compressor pressure to drive the BGF backwards through burners, manifold pipes, and valves safely to the atmosphere through the steam supply vent pipe.

The BGF manifold and supply pipes are designed and verified using CFD, to give equal fuel flow to each burner despite the single entry from the supply line. The construction of branch pipes and the mounting of the manifold accommodates considerable differential thermal expansion between mating parts and yet provides adequate support.

Combustion System

The combustion system [(combustion chambers and dual fuel injectors; see Al-Shaikhly, Mina, Neergard (1994)] is designed to be capable of burning BGF and diesel oil. The combustion system design features a conventional combustor air distribution and aerodynamic pattern, discrete coaxial jet air blast liquid fuel atomization, and a combination of swirl and plain orifice BGF injection with a passive air purge arrangement.

The low calorific value of the BGF reflects on both flame temperature and the increased flow rate required to achieve the rated power output. Both these factors are likely to affect flame stability and low power combustion efficiency. The combustion chamber dimensions are determined by the requirement of physical interchangeability with the standard production Typhoon combustion system. The combustor design is focused primarily on selecting an air distribution that ensures meeting the operational requirements and the emission targets on both BGF and diesel oil. Air admission is split into three main categories: primary combustion air, dilution air, and combustor cooling air.

The primary combustion air is partly admitted through an axial swirler positioned at the combustor dome and is incorporated in the fuel injector. The remainder is admitted through an array of plain holes in the combustor wall. The combustion air distribution gives a leaner than stoichiometric primary zone. The dilution air is admitted through a single array of holes designed to provide the required turbine inlet temperature distribution. Combustor wall cooling is in the form of six axial film cooling stages.

The dual fuel injector consists of two separate cores; one for the BGF and the other for the diesel oil. The BGF assembly combines two injection mechanisms. A large portion of the BGF is injected through an axial swirler which has a defined passage shape

designed to minimize flow separation. This swirler is in a counter-rotating direction to the dome air swirler; this has been shown to promote rapid fuel and air mixing (Kelsall *et al.* 1991). At the full load design point, the primary zone swirl is dominated by the dome air swirler. The remainder of the BGF is injected through plain holes positioned inboard of the BGF swirler. The number and orientation of the holes are designed to match and interact with the primary jets.

During liquid fuel operation, the large volume of the BGF injector passage is open to the hot gas environment of the primary zone. Hence, recirculation of hot gases within the gas injector is inevitable as has been demonstrated in previous attempts to design dual fuel combustors with LCV gas and conventional fuel (Morrison, Pillsbury 1989; Beebe, Blanton 1985). Morrison, Pillsbury (1989) employed steam flow to purge the gas passages when operating on conventional fuel. Gas purge was employed in Beebe, Blanton (1985), but the purge gas and method were not defined.

The passive purge arrangement (Mina 1993) is a feature of the fuel injector design whereby the compressor delivery air is aerodynamically driven to purge the BGF passages. The internal passages of the BGF injector are open to the approach passage leading to the air swirler. The open area is designed to admit a fixed portion of the air to purge the BGF injector passages during the time the combustor is operating on diesel oil. On fuel change-over, and as the BGF pressure increases, the flow of air within the injector is progressively reduced. At full load BGF flow conditions, the BGF pressure is higher than the air pressure in the approach passages and, hence, a portion of the BGF gets split into the air passage and is admitted to the combustion chamber via the air swirler. This initially presented two potential hazards: first, the possibility of BGF spillback, and second, the possibility of flashback into the air swirler approach passage. Initial design calculations and subsequent dedicated and extensive rig tests, with and without combustion, showed no evidence of either event occurring.

This novel approach not only provides purge air, but is also a good tool for resetting the primary zone stoichiometry on change to diesel oil operation, which is not possible if an alternative purge fluid is employed. Hence, the primary zone stoichiometry using diesel oil can be made relatively leaner which is beneficial to NO_x and smoke emissions. On fuel change from diesel oil to BGF, which eliminates the purge air flow, the primary zone stoichiometry becomes relatively richer; this is beneficial for low power CO emission control.

The combustion system development has been performed using a high pressure rig at simulated engine operating conditions from ignition, transient sub-FSNL, and a load range from FSNL to full load. Tests were performed on diesel oil and a synthetic gas mixture.

Ammonia may be present in the actual gasifier-generated BGF. To assess the ammonia to NO_x conversion rates, a dedicated rig test was performed. Ammonia was injected into and thoroughly mixed with the bulk synthetic gas fuel mixture prior to admission to the test rig. The doping level covered a concentration range from 500 to 3000 ppm by volume.

The results of the combustion development programme can be summarized as follows.

- A combustion system design which is interchangeable with the standard Typoon combustion system is achieved.

- Simulation of engine ignition and acceleration to FSNL using diesel oil is satisfactory.
- Load range emissions (smoke, NO_x, and CO), traverse quality, and combustor wall temperature using diesel oil are in line with programme set objectives.
- The lean flame stability limit for diesel oil and BGF is adequate to cover the entire engine operating range and fuel change requirements.
- The novel passive purge arrangement incorporated in the fuel injector design is effective in preventing hot gas ingestion.
- The exhaust gas temperature distributions on both fuels are within the set programme target for satisfactory engine operation.
- The NO_x emission, without ammonia doping, is less than 10 ppm by volume at full load AFR
- In the presence of ammonia in the gas fuel, the emissions of NO_x at full load AFR is less than 50 ppm by volume, for ammonia concentration below 400 ppm by volume, in the BGF.

The Turbine Control Module

The control system used on the EGT Typhoon gas turbine is the Rustronic Mark II. This is a microprocessor-based industrial gas turbine control system which uses an in-house developed software language known as RP2. RP2 is an incrementally compiled, multi-tasking high-level language which is applied in a moulder form. The control system hardware is also developed in-house. Each item is tailored specifically for controlling and interfacing with turbine and turbine-related auxiliary equipment. The hardware is designed in a manner that enables direct interfacing with the plant equipment for controlling valves and monitoring different variables including pressure, temperature, and positions.

The control system for each contract is engineered using the customer requirements specified during the tender stage. The intent of the control system for this application is to use as many standard software and hardware modules as possible in order to keep changes to a minimum.

The special software modules developed specifically for this application are:

- steam injection;
- turbine governing;
- interface with the plant control system;
- automatic load control of the turbine; and
- control of the special dual fuel system which can adjust for variations in the LCV of the gas and its supply pressure.

The plant control system monitors the booster compressor speed and will activate a turbine shutdown signal if a sudden failure of the booster compressor occurs. Due to the nature of the BGF, the gas turbine and relevant systems are enclosed within ventilated acoustic enclosures. A special fire ventilation and gas monitoring and control system has also been developed.

Conclusion

A Typhoon gas turbine has been successfully adapted, together with the associated systems to meet the requirements of a dual fuel BGF/diesel oil application. The systems involved are air bleed, fuel, combustion, and control. The combustion system is designed to be interchangeable with the standard Typhoon combustion system and incorporates a novel passive purge arrangement in the fuel injector which is effective in preventing hot gas ingestion. All systems have been developed to production standards.

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The Netherlands Programme on Energy Generation from Biomass and Waste

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Introduction

Within the European Union, the interest in energy generation from biomass and waste is fast increasing. The reason is two-fold. In the first place, the production surpluses and the corresponding rising expenditures for subsidies in the agricultural sector call for the development of new markets for agricultural products. Should feasible cultivation of biomass for energy utilization occur, positive impacts on the sector may be expected. Application of sustainable biomass and/or biomass waste for energy purposes may lead, in the European context, to sustainable development in the areas of employment, rural development, and long-term investment opportunities. Introduction of biomass energy will result in new markets for agricultural products. New crops will stimulate agricultural activities and contribute to biodiversity. In the second place, the utilization of sustainable biomass for energy generation leads to 'in principle' zero carbon dioxide (CO_2) emissions, which is important for combating the greenhouse effect and acid rain.

Recently, a challenging target has been proposed by the Netherlands Minister of Economic Affairs for the development of the renewable energy sector in the Netherlands. Renewable energy is to contribute, from an actual one per cent share in electricity production at present, a 10% share in the year 2020. It is expected that biomass will be the leading renewable energy source enabling the realization of this target.

Biomass can be converted into useable energy in several ways. Important thermal conversion technologies are combustion, gasification, and pyrolysis. For high oil-content or sugar-content energy crops, physical-chemical (extraction) and biochemical (anaerobic digestion, fermentation) routes are available.

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The Dutch Organization for Energy and Environment (NOVEM) coordinates and stimulates the research, development, and implementation of biomass utilization for energy through the Energy from Waste and Biomass (EWAB) Programme. Priorities of the programme are outlined in its plan of approach. The main efforts of the programme concentrate on thermal conversion technologies for heat and/or power generation. This paper discusses some important programme activities and results.

Availability of Biomass for Energy Generation in The Netherlands

The plan of approach stipulates three possible sources of biomass for energy generation in the Netherlands.

- Indigenous biomass wastes from agricultural, agro-industrial, and waste-processing activities
- Dedicated energy crops grown in the Netherlands.
- Imported biomass fuels.

Besides, in order to stimulate the mitigation of 'greenhouse gas' emissions, the Netherlands Ministry of Economic Affairs has opened a facility for joint implementation of CO_2 reducing energy projects.

Indigenous Biomass Wastes from The Netherlands

An overview of the availability and characteristics of organic waste streams from the waste processing sector, agricultural sector, forestry, and energy crops is given in Table 1. Calculations show that the potential maximum contribution of indigenous organic wastes to Dutch electricity production is about 30–80 PJ per annum or about 4–10% of annual power consumption. Although this amount is high in relation to the target, there are important technical, logistic, and environmental constraints. Application of those wastes is, nevertheless, financially very attractive as some of those wastes at present have a negative value, due to dumping costs and/or costs associated with processing in waste-incinerating installations.

Dedicated Biomass

Both on the national, as well as the European Union (EU) level, research is presently undertaken to evaluate technical and economic possibilities for growing dedicated crops for energy production. In the Dutch context, the following crops are of interest: poplar, willow (wood crops), and miscanthus (straw crops). Depending on agricultural and economic assumptions, the maximum potential contribution varies from 12–70 PJ per annum or about 1.5–9% of the annual power consumption. However, at present, the cost of biofuels from dedicated energy crops produced in the Netherlands is three to five times the cost of coal. For this reason, no important applications are foreseen in the near future.

Table 1

Estimated availability and characteristics of biomass wastes in the Netherlands

Material	Amount ('000 tonnes/ year)	Heating value (GJ/tonne, wb)	Moisture content (% db)	Ash content (% db)	Volatile matter (% db)
Waste processing sector					
Contaminated waste					
Demolition wood	200–275	16	air-dry	0.25–10.7	60–70
Pallet wood	400	16	air-dry	0.25–1.7	60–70
RDF	—	16–21	5–10	9.00–16.0	?
Green waste	1000	5	50–65	14.00–16.0	?
Plastics	—	—	—		
Non-contaminated waste					
Redwood dust/shavings	100	16	air-dry	3.0	60–70
Public garden waste	250	10–16	25–50	3.0	60–70
Residual wood	45	16	air-dry	1.0	60–70
Bark	50	16	—	5.0	60–70
Grass residues	600	8	50	4.0	—
Agricultural sector					
Straw	450	15	15–25	4.4	—
Rapeseed straw	12	?	±15–20	—	—
Forestry sector					
Thinnings	500	13–16	air-dry	0.25–1.7	60–70
Energy crops (not realized yet)					
Miscanthus	1000	17	15–20	—	—
Poplar	1000	10–13	30–50	—	—
Willow	1000	10–13	30–50	—	—

Imported Biomass

Two recent studies commissioned by the EWAB programme on wood import from Estonia and Uruguay for cofiring in Dutch coal-fuelled power stations show that wood import for energy purposes is still a factor 1.7–1.8 (Estonia) or 2.3–2.7 (Uruguay) more expensive than coal. Other than economic motives such as reduction of CO_2 emissions, Dutch energy policy towards renewable energies and/or consumer preference will have to justify the use of this type of biomass. A recent survey by a Dutch electricity company has shown that 5–10% of private consumers are willing to pay 20% more for green power. The share of transport costs in total costs of imported biomass is significant: from 28–30% (Estonia) to 42–50% (Uruguay). To lower transport costs, energy-concentrating techniques in the biomass-exporting country (slow and fast pyrolysis) are currently under consideration.

Joint Implementation

The facility for stimulating greenhouse gas mitigating energy projects is open for cooperation between private companies in developing countries and the Netherlands from 1996 and will be open for cooperation between private companies in Eastern European/ former USSR countries and the Netherlands from 1997. Priorities and conditions are

presently being discussed between the Netherlands Ministry of Foreign Affairs, Department General of International Cooperation (DGIS), the Ministry of Economic Affairs, and the Ministry of Environment (VROM). The joint implementation programme for developing countries will be coordinated by DGIS.

Priorities of the Dutch EWAB Programme

The EWAB programme recognizes the following technological priorities for realizing an increased biomass energy share in Dutch electricity production.

1. Co-combustion of biomass and wood or wood-derived fuels in conventional coal-fired power stations.
2. Gasification.
3. Large-scale power production through biomass gasification.
4. Small/medium scale combined heat and power (CHP) production through biomass gasification.
5. Biomass liquefaction.

Co-combustion

Co-combustion of wood waste and other biomass in conventional large-scale coal-based power plants has shown high electric efficiency and low specific costs. The low-cost reduction of emissions without extra investment in flue gas cleaning equipment and the reduction in CO_2 emissions are two of the major environmental advantages. Two basic options are currently followed in the Netherlands, namely co-combustion of pulverized wood in a pulverized coal power station, and co-combustion of wood gas from a circulating fluidized bed gasifier (CFB) in the furnace of a pulverized coal-based power station.

1. *Co-combustion of pulverized wood in the 635 MWe coal-fired Gelderland EPON power station at Nijmegen.* Waste wood and demolition wood is sorted and processed to raw wood chips at three locations in the Netherlands, after which it is transported to the city of Nijmegen. Two hammer pulverizers (capacity 10 tonnes/hour each) reduce the material from its original size (approximately 30 mm) to particles of 1–8 mm. After that, the material is transported to four pulverizers, where it is further reduced in size and dried with preheated air. The end product is collected in a dust collector. Each pulverizing system works independently and produces 2.5 tonnes of end-product with a density of 200–240 kg/m^3 per hour. The wood product is fed into a static classifier, which removes about 15–20% of the particles which are smaller than 800 micrometers in size. The material returning from the classifier falls into a vibrating sieve in which further separation takes place. The large pieces then go in for further pulverizing. The product from the sieve, together with the product from the classifier, are pneumatically transported in a dosage system, which feeds the power via a fuel pipe to four individual burners. The special wood burners with a total capacity of 54 MW_e are mounted on the side walls of the boiler (two on each side).

   Utilization of waste wood as a secondary fuel cuts down on the consumption of fossil fuels with the result that the CO_2 emissions are significantly reduced. Additional advantages are a reduction of the ash volume and of the SO_2 and NO_x emis-

sions. On an average, five per cent of the combustion energy of the Nijmegen power plant is supplied by wood. The amount of electricity generation based on pulverized wood is 20 MW_e, which replaces 45 000 tonnes of coal per annum. Annually, 60 000 tonnes of pulverized wood is used as a fuel, thus reducing CO_2 emissions by 1 10 000 tonnes. For every 7000 operating hours, a saving of 1.25 PJ is achieved.

The total investments amounted to approximately Dfl 30 million, 5 million of which was subsidized through the Novem and the THERMIE demonstration programme of the European Commission. Construction started in September 1994, and trials in August 1995. The installation went on in January 1996.

2. *Co-combustion of wood gas from a CFB gasifier in the furnace of a pulverized coal-fired 600 MW_e power plant.* This project is currently in the feasibility stage. The idea is to produce wood gas from local or imported wood chips by means of a 60 MW_{th} CFB gasifier. Proven technology is available from two or three suppliers in Scandinavia (TPS, Enviropower, Tampella) and at least one supplier (IGT) from the US. The raw wood gas will be co-combusted with coal in the pulverized coal furnace of the power plant. Present investigations are focused on the cost and availability of wood chip fuel and the selection of CFB technology.

Gasification

Large-scale gasification of biomass, in combination with combined cycle gas/steam turbine power generation, promises high electric efficiencies at acceptable costs. The Netherlands National Research Programme on Biomass Gasification promotes biomass gasification research activities.

1. *ECN pilot biomass CFB gasifier, Petten.* One of the most important targets of the NOB is to realize a pilot plant for gasification experiments. From three proposals, submitted by consortia of research institutes, industry and biomass fuel suppliers, NOVEM has selected the combination of Energy Research Foundation (ECN) Netherlands and Stork Ketels BV Afvalzorg Noord-Holland NV to construct a 350 kWg_{th} biomass gasifier, which will be used for research on the application of biomass and residues. The gasifier will be located at ECN Petten, North Holland. Construction costs are estimated at Dfl 10 00 000, 50% of which is to be provided by NOVEM as a subsidy.

The gasifier is an atmospheric CFB gasifier. If required, the installation can operate under slight over pressure (5 bars). The plan will initially be fuelled by different types of organic wastes, including wood from thinnings, verge grass, straw, waste paper, etc. At a later stage, wood from short rotation coppice (e.g., willow) may be considered. The main objective of the project is to test and characterize the fuels to be used. The project is intended to provide data for power companies which consider utilizing biomass as a fuel.

In addition to a feeding mechanism, a fuel-measuring device and a flare system will be coupled to the gasifier. The installation may be completed with extra facilities such as a system for fuel pretreatment, a tar cracker, a flue gas cleaning system, and a test rig (for testing gas engines, gas turbine components and Stirling engines). Construction of the gasifier started on 1 March 1996. The pilot plant will be operational for a period of 5–10 years as from 1 September 1996.

2. *Biomass gasification pilot plant in the province of North Holland.* The largest biomass gasifier (organic waste and energy crops) in the world will be constructed in the Netherlands, at a location in the province of North Holland. The STAG unit will be the first in the world to supply grid electricity using a gas turbine with a thermal capacity of 50 MW thermal and 30 MW electric capacity. The CFB gasifier will have a capacity of approximately 150 000 tonnes per annum of biomass (dry basis). The installation of the gasifier is an enterprise of the province of North Holland, PEN (the energy distribution company for North Holland), the Dutch Electricity Generating Board, the energy production company UNA, and the Association of Waste Processors. The gasifier will be fuelled with a mixture of agricultural wastes, construction and demolition wood wastes, organic industrial wastes, sewage sludge, and (in future) energy crops. The gasifier technology has been selected and the project is currently in the validation and detailed design stage. Construction costs of the gasifier are estimated at Dfl 100 million. A unique feature of this project is a combination of technologies (catalytic tar cracking, hot gas clean-up, and low heating value gas-fuelled turbine), which have not been demonstrated at this (commercial) scale before.
3. *Standard gasifier fuel fixed bed gasifier for small/medium-scale CHP applications.* Based on extensive monitoring, analysis, and evaluation of existing fixed bed gasifier/gas engine generator units, it was concluded that two major reasons are responsible for the lack of market penetration of such systems.

   Small/medium scale gasifier units have suffered from technical problems like extreme engine wear, unreliable and unstable operations, and undefined and varying gas quality and composition. The main reason for those problems is the occurrence of significant variations in biomass fuel characteristics (moisture content, ash content, morphology, bulk density, reactivity, etc.). The universal fixed-bed gasifier, able to handle all or most fuel types of different characteristics, does not exist, and, in all probability, will not come into being in the near future. Therefore, the wide dissemination of such systems calls for the development of a pretreated standard gasifier fuel.

   Also, small/medium-scale fixed-bed gasifier systems are presently characterized by minimal automatic measuring and control systems. This is caused by the high cost (in comparison to the relatively low capacity) of adequate instrumentation. As a result, the systems often show variable engine power outputs and engine efficiencies at variable loads and variable peak power outputs, and call for the continuous presence of expert, experienced, and motivated personnel. However, the cost of the latter in the Netherlands is not acceptable. These economic constraints can be overcome by applying recent developments from the automotive industry which have led to the development of cheap and reliable hardware (sensors, attenuators) and software. These instruments can be used for the automatic control of the gasifier and gas engine, thereby significantly decreasing the operational costs.

   A consortium consisting of the Biomass Technology Group (BTG) TNO, Royal Netherlands Schelde Group (boiler manufacturer), and EPON (a power distribution company), with financial support from NOVEM and the EU, is currently developing an automatic fixed bed gasification system based on preprocessing of mixed biomass fuels and an advanced briquetting technology. A 200 kW demonstration CHP plant will be operational at the end of 1996. The consortium has defined the European market for the technology in the 200 kW to 2 MW capacity range.

Liquefaction

The rotating cone flash pyrolysis reactor is an invention of the Reactor Engineering Group of the University of Twente, developed in a PhD programme between 1989 and 1993, to maximize bio-oil production. The pilot plant is located at Enschede, the Netherlands. Wood particles, fed to the bottom of a rotating cone, together with an excess of inert heat carrier particles, are converted while being transported spirally along the hot cone wall. Products obtained from the flash pyrolysis of wood dust include non-condensible gases, bio-oil (tar), and char.

The PhD programme led to the construction of a 10 kg/hour laboratory reactor capable of producing bio-oil with a yield of 70% by weight (dry basis (db)). Further development of the reactor technology was initiated by the Food and Agriculture Organization and financially supported by NOVEM, and a pilot plant with a capacity of 50 kg/hour was constructed by a consortium of AKF Royal Schedule and BTG in 1995. In addition to the scaling-up of the original reactor by a factor of five, a new bio-oil collector was developed. In experiments with the pilot plant, a bio-oil yield of 60% weight (db) was achieved.

The plant was shipped to Shenyang Agricultural University (SAU) in China in late 1995, and will be utilized by SAU with support from BTG for a test programme from April 1996 onwards. Pending the outcome of the Chinese test programme, BTG intends developing a demonstration-scale plant with a capacity of 150 kg/hour.

Danish Energy Policy with a Focus on Cogeneration

Lars Nikolaisen[1]

Since the mid-80s, six completely or partly straw-fired cogeneration plants have been built in Denmark. In addition, a test plant has been built and another is under construction. The annual straw consumption is 260 000 tonnes, and will increase to 380 000 tonnes at the end of 1996. The test plant is now running for a two-year period with consumption up to 120 000 tonnes/year. The size of the cogeneration plants ranges from 2 to 30 MW electrical output.

In 1990, the Danish Ministry of Energy launched Energy 2000 – an ambitious attempt to direct fuel consumption towards environmentally acceptable fuel types such as natural gas, solar energy, wind energy, and biomass. The objective of the plan is to achieve the following goals by the year 2005 compared to the situation in 1988 through the following measures.

- Reduce energy consumption by 15%.
- Increase natural gas consumption by 170%.
- Increase renewable energy consumption by 100%.
- Reduce coal consumption by 45%.
- Reduce oil consumption by 40%.
- Reduce CO_2 emissions by at least 20%.
- Reduce SO_2 emissions by 60%.
- Reduce NO_x emission by 50%.

These goals are to be achieved through an extensive conversion to cogeneration of energy in power plants fuelled by natural gas and/or biomass.

According to Regulation No. 6/1990 from the National Agency on Environmental Protection on limiting air pollution from industries, the only emissions limits for straw and wood chip fired plants larger than 1 MW are 40 mg/Nm^3 for solid particles and 0.05% CO

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(volume percentage at 10% O_2 in the flue gas) for CO emissions. However, in the environmental approvals of the seven plants, there are further individual restrictions on the emission of NO_x and SO_2.

To fulfill the Energy 2000 goals, there is an endeavour also to develop biomass-fired gasifiers with 0.5–5 MW electrical output. The research effort in the gasification field is directed towards development of technology for small gasifiers, first for straw and later on for wood, both of which can supply a gas that is sufficiently clean for motor fuel and with a comparatively high energy efficiency and economy. The grid connection from small cogeneration plants can face heavy problems due to bad quality of voltage, frequency, and power factor (cos φ).

In Denmark, the specifications in a 10 kV system are:

- voltage: 10–11 kV
- frequency: 49.0–50.3 Hz
- Cos φ: −0.1–0.4

Normally, the stiff grid in Denmark does not cause any trouble when small generators fulfilling the above limits are connected to the grid. In soft grids, it is recommended that the specifications of the generator are strengthened according to electrical insulation and mechanical strength.

Biomass-based Small Cogeneration Technology Application in the ASEAN Region

Saswinadi Sasmojo[1]

Introduction

The Association of South East Asian Nations (ASEAN) member countries, namely Brunei Darussalam, Indonesia, Malaysia, the Philippines, Singapore, and Vietnam, are currently experiencing high economic growth rates. The demand for energy in the region is, therefore, steadily and considerably increasing.

Except for Singapore and Brunei Darussalam, the agriculture and forestry sectors of the other countries have a sizeable share in the economy. One of the important components of the two sectors is food crop production - particularly rice, palm oil, coconut oil, sugar, rubber, and wood production.

The processing of the harvested products from these activities is reasonably energy-intensive, requiring both heat and electricity. Theoretically, many of those processing systems are self-sufficient in energy since the amount of biomass wastes generated is adequate to supply their energy needs, both heat and electricity, through cogeneration. However, many of the production units that were constructed during the 70s and afterwards, while generating their heat requirements from biomass residues, are generating their electricity needs from diesel-driven power plants. Even some of the older systems which were already practising biomass-based cogeneration have switched to diesel engine driven power generators for their electricity needs. Apparently, investment cost consideration, and the availability of low-price petroleum products made those systems technically and economically more attractive.

However, from the end of the 1980s, there has been a revival of drives and initiatives on the use of non-fossil resources for energy, even though the region is a net energy ex-

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porter, more so Brunei, Indonesia, Malaysia, and Singapore. These moves were stimulated by the sudden considerable increase in oil prices in 1973, and the subsequent 15 to 20 year's experience in coping with the dynamics of world oil supply and prices; and the developments in the international political arena, whereby concern for, and attention to the state of the environment are gaining increasing momentum. The use of non-fossil fuels would, of course, be also beneficial to state-run utility enterprises, as the pressures for capital investments in capacity expansion to cope with the high rate of growth in electricity demand (which ranged from 3 to 16% per year during 1985–1990) can then be relieved. The described climate would also provide better incentives for the agro-industries to utilize their biomass wastes, not only to generate heat, but also electricity.

Potential for Biomass Cogen Technology Application in ASEAN

Under the European Commission (EC)–ASEAN cogen programme, preliminary studies on the potential of biomass cogeneration system in the agro-industry were made. Prospective applications of biomass cogeneration systems were found in the sugar, palm oil, coconut, rice, and wood industries. Typical energy requirements and generated biomass wastes in each of these industries of the region are illustrated in Table 1.

As previously pointed out, cogeneration application potentials was found in five agro-industry sectors, namely, the coconut, palm oil, sugar, rice, and wood industries. The biomass waste generation runs at 30 to 70% of the total processed material. The total energy equivalent of the generated waste is around 25 million tonnes (mt) of energy, which is approximately equal to the total industrial primary demand of the ASEAN member countries. About 50% is currently used as a energy source. The contribution to industrial energy demand is about 20% of the total primary energy demand in that sector.

The following paragraphs provide further observations on each of the five identified potential agro-industry sectors.

Coconut Industry

The major coconut producers in the region are Indonesia and the Philippines. Indonesia produces 27%, while the Philippines produces 32% of the total world production of coconut.

The main generated biomass from the coconut industry is shell and husk, amounting to 17 and 35% of the fresh fruit respectively. The estimated energy equivalents of the generated husk and shells in ASEAN are 2.7 and 1.8 mt respectively. There are competing uses of those forms of biomass aside from energy. Coconut shell is also used to produce high-valued activated carbon, while the husk fibres are also used to make ropes and pad of car seats.

The main products of the coconut industry are desiccated coconut and coconut oil. The energy need for desiccated coconut is 1700 MJ/tonne of fresh weight, while for oil production, it is 4200 MJ/tonne of the oil produced, of which 3000 MJ is as direct fuel and 334 kWh as electricity.

Table 1

Typical energy requirements and biomass wastes generation of agro-industries where cogen applications are prospective in the ASEAN region

Industry	Intake capacity	Main product rate	Energy requirement		Generated biomass wastes
			Electricity	Heat	
Coconut oil	Copra (1 tonne)	Coconut oil (kg)	334 kWh per tonne of crude oil	3000 MJ direct fuel per tonne crude oil	Process effluent (may be used to generate biogas)
Dessicated coconut	Whole coconut fruit (20% meat) (1 tonne)	Desiccated coconut (five per cent moisture) 190 kg	?	1700 MJ	17% shell and 35% husk of whole coconut fruit
Palm oil	Fresh fruit bunches (1 tonne)	Palm oil (140–200 kg)	20–25 kWh	0 73 tonnes of steam	6 5 m^3 biogas potentials from palm oil effluent 210 kg fibers + shell 230 kg empty bunch
Rice industry	Paddy (1 tonne)	Rice (700 kg) (90% white rice and 10% parboiled in Thailand; otherwise 100% white rice)	• 20 kWh (sun drying) • 60 kWh (mechanical drier) • 60 kWh/tonne (parboiling)	? ? ?	250 kg rich husks — —
Sugar mill	Sugarcane (1 tonne)	Sugar (100–120 kg)	25–30 kWh/ tonne	0 4 tonnes of steam	290 kg bagasse
Wood industry	Debarked wood (1 m^3)	• Sawn wood (0.5 m^3) • Plywood (0.52 m^3)	 1.2 tonne steam per tonne of plywood	35–45 kWh/m^3 plywood 110 kWh/m^3 plywood	0 5 m^3 wood wastes —

Palm Oil Industry

The palm oil industry produces the highest quantity of biomass residues, about 705 of the fresh fruit bunches. The residues comprise empty bunches, fibres from the husk, shells, and liquid effluent, known as palm oil mill effluent (POME). The 376 EC–ASEAN cogen programme identified that oil mills in the ASEAN region are mostly located in Malaysia, and account for about 75% of the total ASEAN production. The generated solid

residue amounts to over 21 million tonnes per year, which is equivalent to about 4 million tonnes of oil equivalent (mtoe) per year. This makes most of the palm oil mills self-sufficient in energy by producing the required heat and power from the generated shells and fibres. The empty bunches are presently incinerated or used as fertilizer.

While the cogeneration potential of the palm oil industry in ASEAN is high, there are some constraints to the profitable application of the system where excess power can be sold to the utility. Firstly, palm oil mills are generally located in remote areas and their capacities are small. Second, competing uses exist for the generated residue. The shells provide good raw material for producing charcoal and activated carbon, which offer higher value alternative uses, whereas all the fibres are practically consumed for the plant's cogenerated energy needs. Only the empty bunches are available to generate excess power for external electricity sale. However, the technology for this is yet to be developed, implying an opportunity to undertake the relevant R & D.

Another potential energy source from palm oil mills is POME. For each tonne of POME, one can potentially produce 5–10 m^3 of biogas. The generation rate of POME per tonne of palm oil produced is about 2.5 m^3.

Cane-sugar Industry

Cane-sugar mills in ASEAN operate seasonally, usually three to six months in a year. The generated biomass residue is bagasse, which is mostly used as cogeneration fuel to provide the required heat and power needs of the mill. The three major cane-sugar producers are Indonesia, the Philippines, and Thailand. Though Thailand is a new entry, the development there has been very dynamic.

The survey undertaken by the EC–ASEAN cogen programme indicated that there are 151 sugar mills in ASEAN, producing 26 mt of bagasse per year, which, potentially, is capable of producing 4.6 mtoe of energy.

The overall technical potential of the ASEAN sugar mills for power generation through cogeneration is 8600 GWh, of which at least 6800 GWh is exportable. Considerable systems improvement is necessary to tap that resource, as current systems are old and inefficient. Higher pressure steam boilers have to be put in place, to replace the existing ones.

Rice Industry

The biomass residue generators of the rice industry are the rice mills. There are about 100 000 rice mills in ASEAN, generating 19 mt of rice husk per annum, with an energy content of 6 mtoe.

The electricity generating potential of rice husk generated from rice mills is about 100 kWh per tonne of paddy processed, while the power requirements are 20 kWh/tonne of paddy for white rice production and 60 kWh/tonne of paddy for parboiled rice production.

While Indonesia is the largest rice producer in the region (twice the production of Thailand and four times that of the Philippines), the individual rice milling operations in Indonesia are very small, and so is the capacity of the milling units. The potential for economically profitable cogeneration can be found in Thailand (about 30 mills), and the Philippines (about 40 mills), where the milling capacities are 7 tonnes/hour or more. The total power production potential from such mills of the two countries is 400 GWh.

To harness the energy potential from the paddy husk generated by the rice mills in Indonesia, which is about 3.5 mtoe, economically-efficient very small cogeneration systems, having power generation capacities as low as 25–100 kW have to be developed.

Wood Industry

The main production systems of the wood industry in ASEAN are found in sawmills and in plywood and furniture industries. The waste generation of these systems is very high; about 50% of the intake is converted to waste.

Most sawmills in the ASEAN region are either grid-connected or use diesel generation to meet their power needs. The power requirement typically is 35–45 kWh/m^3 of processed wood. The total number of sawmills in ASEAN is over 4000, the majority of which are in Indonesia and Malaysia. However, it has so far not been possible to estimate the total capacity, and, therefore, the generated wood wastes from the sawmills.

The EC–ASEAN cogen survey identified 237 plywood industries in the region, of which 108 are in Indonesia, 60 in Malaysia, and 21 in Thailand. The total capacity data with regard to sawmills has not been compiled as yet.

Typically, the energy requirements comprise 110 kWh of electricity and 1.2 tonnes of steam per cubic metre of product. Presently, many of the plywood factories depend on diesel gensets and bunker oil for their energy needs. Only the most modernized and biggest companies use waste wood to cogenerate heat and power.

Subject to some basic constraints of the industry towards more integrated processing facilities, the wood industry offers the most promising cogeneration market. Financial analysis of three projects supported by the EC–ASEAN cogen programme indicated a very attractive internal rate of return and payback period, ranging from 1 to 2.5 years.

Biomass-based Cogeneration Technology Implementation in the ASEAN region through the EC–ASEAN Cogen Programme

The significant potential for biomass-based cogeneration technology in the ASEAN countries has provided the justification and impetus for implementation activities. The EC–ASEAN cogen programme has, therefore, undertaken further steps, whereby cogeneration system implementation is to be introduced through a full-scale demonstration project (FSDP).

The EC–ASEAN cogen programme defines an FSDP as 'the implementation of a proven technology on a full-scale basis in order to demonstrate its reliability and economic viability'. Under this scheme, prospective users are identified, and encouraged to submit investment proposals, whereby up to 15% of the costs can be funded from the EC–ASEAN cogen sources.

Once the cogen plant is put on stream, a monitoring programme is to be undertaken, whereby the operational performance would be recorded, and the results made available to other interested parties. After the monitoring activities are completed, study tours to FSDPs may be organized for parties interested in the technology.

To provide some idea of the cogeneration systems that have been implemented or will soon be in operation through the EC–ASEAN cogen FSDP scheme, copies of the

project descriptions published by the EC–ASEAN cogen programme are included in Annexure 1.

There are currently 29 potential proposals under consideration in the region, eight from Indonesia, five from Malaysia, six from the Philippines, two from Singapore, and eight from Thailand.

The observations on the current development of biomass-based cogeneration technology in the ASEAN region presented in this paper by no means project a complete picture of what has been happening in the area. For those who are interested to obtain further information, it is suggested that inquiries be addressed to the Coordinator, EC–ASEAN COGEN, the Asian Institute of Technology, Bangkok, Thailand.

Annexure 1

Description of selected FSDPs of the EC–ASEAN cogen programme

1. Heat and power production from wood waste, Sarawak, Malaysia.
2. Heat and power production from wood waste, Bentong, Malaysia.
3. Steam recovery for power generation, Panom Sarakham, Thailand.
4. Cogeneration in the rice milling industry, Chakkaraj, Nakom Rattchasima, Thailand.
5. Cogeneration from wood residue, Surat Thani, Thailand.

International Experiences in Bagasse-based Cogeneration[1]

Dan Jantzen[2]

Transparency 1
Brazil

Mill	tcd	Installed capacity (MW)	Export (MW)
Santa Adelia	10000	8 0	1 0
Sao Martinho	35000	19 0	1 6
Sao Francisco	6700	3.0	0 3
Cresciumal	6000	5.4	0.3
NS Aparecida	7600	5 8	1 0
Santa Cruz OP	18000	11 4	1 2
Ester	9000	7 4	1 0
Vale do Rosario	17000	16 0	4.0
Santa Elisa	22000	13 0	5.0
Bonfirn	20000	14 0	1 2

[1] Reproduced as presented at the conference, with minor modifications

[2] Renewable Energy Project Support Office, Winrock International, 7, [illegible]g, Vasant Vihar, New Delhi - 110 057, India.

Transparency 2
Central America

Mill	tcd	Export (MW)
El Viejo, Costa Rica	4200	5
Izalco, El Salvador	—	1
Pantaleon, Guatemala	9000	10
La Union, Guatemala	5500	6
Concepcion, Guatemala	7000	10
MadreTierra, Guatemala	2800	5
Santa Ana, Guatemala	6500	8
Yojoa, Honduras	—	4

Transparency 3
Countries with power exporting sugarmills

1. Brazil
2. Central America
    - Costa Rica
    - El Salvador
    - Honduras
    - Guatemala
3. Fiji
4. India
5. Mauritius
6. Pakistan
7. Philippines
8. Reunion
9. Thailand
10. USA

Transparency 4
Brazil

1. World's largest producer of sugarcane
2. Large *world class* mills – sugar and ethanol
3. Low power tariffs; no power investment

   - $0.018 in 1992
   - $0.041 in 1993

4. State government utilities, and sugar industry taskforce planning expanded program

Transparency 5
Central America

- Power tariffs of $0.04 to $0.07
- Sugar industry showing interest in power export
- A few mills adding equipment (new and used) for power export

Transparency 6
Fiji (Lautoka: export 7.5 MW, Labasa: installing 10 MW system, 5 MW export)

- Tariff $0.064 attractive to sugar industry
- Islands have limited power demand; supply is mainly hydro
- Four sugar mills
- As power demand increases, cogen being integrated into the power system

Transparency 7
Mauritius

- Medine: 6 MW export
- Fuel: 22 MW export; coal and bagasse
- Union St. Aubin: 26 MW export – long negotiations
- World Bank project for bagasse cogeneration
- Analysing the system of central power plant and satellite sugar factories

Transparency 8

Philippines

- Busco: export 8 MW
- Tarlac: collecting cane trash for fuel since 1987 using conventional hay balers
- Difficulties getting power sale contracts and reasonable prices

Transparency 9

India

- Five small (1–3 MW) exporters: Cheyyar, MRK, Dutta SSK, Jawahar SSK, Dhampur
- Thiru Arooran: 12.5 MW export
- Under construction: EID Parry, Dharani
- Some states offering Rs 2.25 = $0.065
- Growing interest
- Future growth depends on purchase terms

Transparency 10

Pakistan

- Shakarganj: 3 MW export
- Ashraf· 4 MW export
- Fatima: 3 MW export
- Sell power *as and when available*
- 300 MW potential

Transparency 11
Reunion

- Bois Rouge: 60 MW export; coal and bagasse
- Beaufonds: 20 MW export; bagasse
- Le Gol: 64 MW export: coal and bagasse
- Utilize all the islands' bagasse for power export and supplement with coal in the off-season
- Utility participates in power plant ownership

Transparency 12
Thailand

- Eight mills selling 2–4 MW each on *as available* basis
- The Energy generation of the Thailand (EGAT) utility offers tariff based on capacity and energy, but a five-year contract required to receive capacity payment
- Energy wasted due to inability to negotiate acceptable contracts

Transparency 13
United States

- Hawaii sugar industry facing decline; several cogen plants closed; five cogen plants still operating
- Two large plants under construction in Florida: Okelanta (70 MW installed capacity); Osceola (55 MW installed capacity)

Combined Heat and Power Production in IEA Member Countries[1]

John Newman[2]

Introduction

Combined heat and power (CHP) production has undergone several periods of growth and decline in its century-long history. In the early decades, the inherent wisdom of using the heat otherwise exhausted during electricity generation, and the limited availability of electricity in non-urban areas in most countries encouraged CHP. Later, economies of scale in the production of electricity through conventional thermal cycles led to the construction of larger and more efficient power generation facilities sited further and further from, both, population centres and industrial facilities. This expanded the market for grid-supplied electricity and limited the market for heat exhausted from power stations by increasing the distances over which the waste heat would need to be transported. CHP, therefore, fell from favour for all but a few applications.

Interest in CHP revived between the mid-1970s and the early 1980s. The two oil shocks focused attention on ways to cost-effectively reduce energy waste, and the scale of conventional power plants began reaching a point of diminishing returns. Additionally, advances in the efficiency of CHP systems improved their cost-effectiveness, especially for smaller applications. Member countries of the IEA[3] responded to the promise

[1] The views expressed in this paper are those of the author. They do not necessarily reflect the official position of the International Energy Agency (IEA) or of the governments of IEA member countries. The material is drawn from an unpublished IEA working paper *Combined and Power Generation in IEA Member Countries* (October 1994).

[2] International Energy Agency, 2, Rue Andre Pascal 75775 Paris CEDEX, 16, France.

[3] IEA is an autonomous body, established in November 1974 within the framework of the Organization for Economic Cooperation and Development (OECD) to implement an international energy programme. IEA participating countries include Australia, Austria, Belgium, Canada, Denmark, Finland, France, Germany, Greece, Ireland, Italy, Japan, Luxembourg, the Netherlands, New Zealand, Norway (by special agreement), Portugal, Spain, Sweden, Switzerland, Turkey, the UK, and the US. The Commission of European Communities also takes part in the work of the IEA. Iceland and Mexico are members of the OECD, but not the IEA. Six OECD members – Australia, Kuala Lumpur, Mexico, New Zealand, and the US – are members of the Asia–Pacific Economics Cooperation (APEC) group.

of this technology by promoting its growth through information campaigns, technical audits, and financial incentives for the installation of CHP systems; requirements that utilities purchase power from, and provide back-up power to, users of CHP systems (sometimes at preferential prices); preferential gas transportation prices; and exemption from environmental licensing requirements for plants below a certain generating capacity (corresponding to an air emissions threshold level).

The popularity of CHP declined again somewhat during the mid-1980s, as falling real energy prices dimmed the financial attractiveness of CHP, and reduced the importance that some countries attached to increasing its use. Moreover, the electricity supply/demand balance in some countries reduced the importance of new capacity from CHP systems. The lower energy prices and abundant electric-generating capacity reduced the avoided cost' which some countries use as the basis for evaluating the cost savings associated with electricity and heat produced by CHP plants. Furthermore, the improved efficiency of gas turbine generating systems led to a class of independent power producers capable of competing with electric utilities on electric production alone – without the need to use or sell the heat.

More recently, concerns about the potential environmental impacts of energy use have refocused attention on strategies for reducing the emissions of a variety of pollutants, especially CO_2. CHP systems are attractive in this context because, in many circumstances, they can produce a given amount of electricity and useful heat more efficiently; and presumably with lower emissions, than can conventional facilities like separate electricity generations and boilers. However, as discussed in the next section, CHP's claim as an environmentally preferred method for producing electricity and heat requires a thorough examination of many site-specific factors.

Beyond Thermodynamic Efficiency: Energy, Environment, Economics, and Integration with Utilities

In general, CHP systems can convert approximately 75–80% of the energy content of fuel into electricity and useful thermal energy. Though impressive, especially compared with conventional electric production systems at 30–40% and even new combined-cycle gas turbines systems capable of up to 52% efficiency, such general efficiency estimates do not take into account the very different storage, transport, market, and reliability requirements of the two products – electricity and heat (Verburggen 1992; Veburggen, Dufait, Martens 1993). Nor do they give a clear picture of CHP's energy, environmental, and economic characteristics, which interest policymakers and investors. This section discusses some of the many factors that affect the energy savings, environmental benefits, project economics, and integration with utilities.

Energy Savings and Environmental Benefits

The energy savings and environmental benefits of CHP are very site-specific. They depend upon the form and quantity of fuels that the CHP systems use and displace, and on the emissions controls that the CHP and alternative systems employ. An example might be one in which municipal solid waste would be burned in order to generate electricity

and heat, the latter being distributed to an adjacent community, with the alternative being the production of electricity in a fossil fuel fired power plant, combined with individual space heating by natural gas. Or, perhaps, if a district heating CHP system relies on coal to provide heat to buildings, which would have otherwise consumed natural gas, each system has the potential to produce a different mix and quantity of emissions at different locations, with the gas-using systems having an apparent advantage. However, central plants can be equipped with tall stacks and flue gas cleaning devices to minimize the potential environmental disadvantages.

Further, the potential energy-efficiency gains of CHP need to be determined, through a thorough examination of the purposes for which the waste heat is being employed, as compared with the alternatives. It is often accepted at face value that all of the heat produced or displaced by the CHP system is useful. CHP systems can frequently be oversized, relative to the existing load and/or relative to the efficient load (i.e., the energy required to perform the service using a device more efficient than the incumbent). The former results in the unnecessary exhaust of waste heat, while the latter results in the capture of waste heat which is subsequently lost, for example, in poorly insulated pipes.

Project Economics

The economics of CHP at a given location are based on the physical features of the site, the building, or the industrial process into which the CHP system is to be integrated, and the energy sources (and prices) available for both CHP and the alternative. Although the following factors are not preconditions for the successful development of CHP for a specific application, they can contribute to the project's overall attractiveness.

- Relatively constant and well-balanced requirements for heat and electricity.
- Favourable physical site conditions, e.g., short distances for heat transport.
- A low-cost supply of fuel, e.g., wood waste at a paper-processing plant.
- Correspondingly higher costs for a separate supply of heat and electricity.
- Energy costs that represent a significant share of total operating costs.
- Operator experience with CHP or electricity generation.

Relatively constant and well-balanced requirements for heat and electricity are an especially important consideration because of the real-time nature of electricity and thermal needs and production The existence of an electric grid that will purchase surplus electricity, and provide back-up power, gives important flexibility to the design and operation of a CHP system, allowing the electricity output of the CHP system to be essentially decoupled from the site's needs physically. Without a grid, the selection and design of the CHP system is driven by a need to follow the electric and thermal requirements of the site simultaneously – not an easy task for CHP systems which have relatively fixed output ratios between these two products. The existence and expected persistence of a 'base-load' thermal requirement is also very important. For industrial applications, constantly changing industrial technologies and processes and changing plant configurations (i.e., consolidations and closures) will limit the number of sites suited to CHP.

CHP plants typically require the investor to incur incremental up-front costs relative to the alternative (in most cases, production of heat and purchase of electricity), in order

to reduce operating costs. The investment considerations faced by a potential CHP facility owner/user are similar to those for conventional investments in energy-efficiency equipment – limited financial resources and competing appeals for capital; limited technical and cost-benefit information; short investment horizons, particularly for individual investors; and split incentives between investors and users of energy equipment that encourage first-cost minimization to the possible detriment of energy-related savings over time.

However, CHP has four features that distinguish it from end use efficiency investments. First, CHP results in two products – electricity and thermal energy – that are relatively familiar, uniform, and present in most facilities. Second, CHP plants do not affect critical parts of the production process, as might be the case with other efficiency measures. What is more, CHP systems affect a relatively larger share of a facility's energy requirements through a single investment, as compared with motors, lighting systems, and heating, ventilation and air-conditioning (HVAC). Finally, because of the high capital costs, CHP investments are more likely to be championed by a person or department responsible for total facility energy costs, and who is in a position to evaluate the energy consequences of different plant investments.

Under certain circumstances, it becomes preferable for an independent business entity to invest in CHP and sell the electric and thermal products to one or more users (including the electric utility). Third-party investors may bring certain strengths to the project such as financial leverage and flexibility, tax advantages, risk diversification, and operating expertise. The existence of different parties requires a more explicit consideration of the value of the electricity and thermal energy produced, although the basic financial decision depends on a comparison between an initial investment and an associated annual cash flow.

Integration with Electric Utilities

Though most CHP systems are developed by entities other than an electric utility, the economics of CHP projects are affected greatly by the form of electric utility structure and the institutional, commercial, and legal relationships between the utility and owners of non-utility generation. The manner in which CHP systems interact with electric utilities must be viewed against the backdrop of the utility ownership and regulatory system within the country.[4] At the core of this relationship are two issues, namely commercial considerations, including two-way sales of electricity and capacity between the CHP owner and utility; and obligations of CHP owners to operate as part of an integrated system.

Commercial Integration

CHP systems owned by non-utilities may be sized, designed, and operated to provide as much of the site's electricity needs as possible, sell output to the grid, or to do both. The decision depends largely on the relationship between the utility's tariffs and marginal costs. From the perspective of the CHP owner, the prices charged by the utility rep-

[4] Dufait (1993) provides a review of utility attitudes toward CHP within the European Union, see also MGE (1993)

resent the costs which can be avoided by the CHP system, while the utility's marginal cost is typically the basis, or in some cases, the ceiling for payments made to power suppliers. Although this relationship will change over time, retail prices, inclusive of transmission and distribution capacity costs, are typically higher than the generation-based payments to independent power suppliers. Thus, supplying power to satisfy the site's needs is usually more attractive than selling the same power to the grid, although the grid can certainly be a valuable sink for excess power.

In addition, those served by a CHP system will also need to purchase power from the utility for maintenance, back-up, or supplementary reasons, unless the site is grid-independent by either choice or circumstance. From the perspective of the electric utility, provisions need to be made for periods when the CHP system is unavailable; choices include either the installation and maintenance of redundant capacity which carries a cost, or plans for curtailing the load.

Physical Integration

Under most forms of utility ownership and regulation within the IEA, generation utilities are granted certain rights in exchange for certain responsibilities. Owners of CHP systems, whether producing electricity for their own use or for sale, typically, do not have the same obligations. Thus, under the familiar vertically integrated structure, utilities generation planning and operation become more complicated and administratively costly when CHP systems operate somewhat independently of the planning and dispatch functions of the utilities. Commercial contracts for power purchases by the utility can be designed to ameliorate some of the utilities risk, by offering terms and conditions that reflect the value associated with different services offered by power plants. These may include incentives for availability during the utilities peak periods, reliability during system emergencies, voltage and frequency support, and system longevity, and/or penalties for early retirement.

Some countries are changing the structure of their electric supply industries in order to introduce competition into the generation and, in some cases, the supply of electricity (IEA 1994a; 1994b). Under such circumstances, the planning and dispatch of electricity are likely to be dictated increasingly by market forces rather than regulatory or government fiat. It is expected that this will open up additional opportunities for CHP in those systems that have been closed to independent power production. Conversely, in those systems that have provided financial support for CHP in the form of guaranteed power purchases at attractive prices, the increased competition may serve to limit or eliminate the guarantees.

CHP Applications and Role in Energy Supply

CHP is used most extensively in industrial facilities, e.g., in petroleum refining, chemical, metallurgical, food processing and pulp and paper plants that commonly have high steam demands and abundant combustible by-products. CHP is also used in district heating systems serving residential, commercial, and, occasionally, industrial loads; recently, in-roads have been made into various sub-sectors of the commercial market, including hospitals, hotels, health clubs, universities, laundries, and multi-unit residential buildings.

Table 1 shows the shares of CHP electricity produced by public suppliers (privately or publicly owned companies which, as their primary activity, generate electricity and/or heat for sale to third parties) and autoproducers (companies that generate electricity and/or heat, wholly or partly for their own use in support of a different primary activity). Public suppliers typically use CHP for district heating applications and autoproducers typically use it for industrial applications. The table shows that in some countries nearly all of the CHP production is by autoproducers (e.g., Australia, France, Greece, Ireland,

Table 1
Shares of CHP electricity generation: 1993 (%)

Country	*Auto producers*	*Public producers*
Australia	100	0
Austria	—[a]	—
Belgium	0	100
Canada[b]	—	—
Denmark	1	99
Finland	47	53
France (1990)	84	16
Germany[c]	—	—
Greece	100	0
Iceland	0	100
Ireland	100	0
Italy	96	4
Japan	—	—
Luxembourg	0	0
Mexico	—	—
Netherlands	20	80
New Zealand	100	0
Norway	0	100
Portugal	83	17
Spain	100	0
Sweden	41	59
Switzerland	61	39
Turkey	100	0
UK	100	0
US	76	24
Total OECD	63	37

[a] indicates data not available; [b] country report in IEA (1994b) states that most CHP production comes from autoproducers; [c] country report in IEA (1994b) shows 58% of CHP capacity at autoproducers and 42% at district heating facilities in 1990

Note Figures are estimates of shares of CHP electricity production The underlying statistics count all output from electricity plants having CHP units as CHP production, even in cases where CHP units represent a small portion of a plant's capacity, and where CHP units are not always run in CHP mode

Sources IEA/OECD electricity statistics and country report in IEA (1994b)

Portugal, Spain, and UK); in others, nearly all the facilities are operated by public entities (e.g., Belgium, Denmark, Iceland, the Netherlands, and Norway). The table also points out that CHP data is not reported in quite a few IEA member countries, including several APEC members.

Industrial Applications

Industrial sites (petroleum refining, chemical, metallurgical, and food-processing plants, and pulp and paper mills) are the most traditional sites for CHP facilities. This is due to several factors. significant thermal requirements that are process-related and not subject to daily and seasonal weather-related fluctuations; sites that are typically zoned for power production; availability of low-cost fuel sources in a number of industries (e.g., wood waste in pulp and paper mills); operations and maintenance personnel with competence in power systems, and energy cost reduction goals that are aligned with strategic business interests.

A representative of independent power producers has expressed the requirements for further development of CHP systems in industry as follows (Hamrin 1988):

- Clear and equitable interconnection specifications to the electric grid
- Unbiased electricity stand-by rates and demand charges
- Stable fuel supply
- Stable regulatory environment
- Predictable and sufficient revenue stream and
- Power purchase agreements that can be financed without open-ended liabilities.

Two factors need special attention when contemplating the viability of CHP in industrial settings – the expected persistence of the thermal loads, and the tolerance and back-up for CHP system outages. Constantly changing industrial plant configurations (including consolidations, closures, and the introduction of new electric-based technologies) will limit the number of sites suited to CHP. It is not at all clear that the thermal load at a given industrial site will endure at the quantities necessary to ensure the financial success of the project. Regarding system outages and availability, depending upon the technology employed and the manner in which it is maintained, the system may be more or less prone to scheduled and unscheduled outages. While back-up electricity is normally available from the grid, different types of industrial facilities have different levels of tolerance for the loss of thermal load. Typical responses are attempts to 'coast through', shut down production, or maintain redundant thermal capacity. The latter two entail costs.

Finally, the availability and price of natural gas, the fuel of choice for many systems due to the efficiency, and cost improvements to gas turbine-based CHP systems will influence the level of CHP development for this market.

District Heating

District heating (DH) systems, in which steam or hot water is produced in centralized plants and circulated to end users through a piping network, tend to be built around the same basic concepts that led to the centralized production and distribution of electricity:

economics of scale, diversity in use (load timing), and increased efficiency. Moreover, DH offers additional advantages over the use of individual heating equipment, the most notable being the ability to take advantage of low-cost fuels, such as municipal solid waste, biomass, and waste heat from a CHP facility, which may not otherwise be available (or practical) for individual users. Additionally, it is more straightforward to switch fuels at a centralized location as opposed to a number of individual heating systems. This introduces an energy security dimension to DH systems. However, fuel diversity and flexibility become somewhat less significant when CHP systems are based on combustion turbine or reciprocating engine technologies, since these tend to rely upon natural gas or light distillates.

The overwhelming predominance of the distribution-related capital costs leads to two characteristics in DH systems.

- They are more common in areas that have heat requirements amenable to the minimization of these costs, e.g., high thermal density and relatively balanced thermal load on a daily and seasonal basis.
- They tend to require some level of government involvement to become established.

In most regards, the decision to install a CHP plant as part of a DH system will depend on many of the same factors as are applicable to an industrial installation, including the timing and nature of the thermal load, fuel availability, and opportunities for the economic use of the electricity. However, the different settings into which these systems are introduced will lead to a different set of ownership, market impact, decision-making, heat delivery, grid connection, load pattern, and technology preference characteristics.

Residential and Commercial Systems

Developments in CHP technology over the past 10 years have led to the introduction of small-scale systems that can, under selected circumstances, meet the needs of commercial buildings or multi-residential complexes. Some of these users have energy requirements similar to those of the energy-intensive industries discussed earlier – balanced and constant electric and thermal loads, energy costs that are a significant share of the total operating costs, etc. These conditions exist year-round in hospitals, hotels, laundries, and health clubs, but only seasonally in schools.

The advances in CHP technology that have made in-roads in these markets include smaller-scale, typically engine-based systems, prepackaged designs (in order to reduce capital and installation costs), sound attenuation devices, standardized electrical connections, simplified maintenance requirements, and environmental controls. These systems are usually fuelled by natural gas. In some cases, the systems have been combined with absorption chilling units in order to increase the opportunities for using the waste heat.

As discussed previously, CHP implementation is limited by the same factors that influence the adoption of energy-efficiency technologies. This is particularly true in the commercial and residential sectors, where institutional arrangements tend to result in a first-cost focus on the part of the building developer, with an ongoing responsibility for energy costs being assigned to the building owner/manager or users.

Role of CHP in Electricity Supply

Table 2 shows the contribution of CHP to electricity supply. It should be noted that the quantities of electricity reported in this table do not reflect the extent to which the power plants were actually operated in the CHP mode. Since plants designed as extraction/condensing units can be operated entirely in the condensing mode, electricity output from a CHP facility does not imply that waste heat was actually used. Moreover, the entire production of any power plant that includes a CHP unit is counted as CHP production, even if the unit represents a small share of the total plant capacity.

Table 2
CHP share of electricity supply

Country	*Production (1993)*[a]			*Capacity (1990)*[b]		
	CHP electricity production (TWh)	*Share of total electricity supply (%)*	*Share of fossil fuel electricity supply (%)*	*CHP electricity capacity (GW)*	*Share of total electricity capacity (%)*	*Share of fossil fuel electricity capacity (%)*
Australia	6.1	3.7	4.1	—[b]	—	—
Austria	2.5[c] (1990)	5.0[c]	13.8[c]	0.8[d]	4.9[d]	15.8[d]
Belgium	7.2	0.2	26.0	1.8	12.7	24.9
Canada	—	—	—	2.0 (1989)	2.0	6.9
Denmark	29.3	86.7	89.5	5.0	57.0	55.7
Finland	19.9	32.5	71.7	—	—	—
France	4.0 (1990)	1.0	8.4	1.6	1.6	9.6
Germany	52.0 (1990)	9.5	13.4	18.7	14.8	20.7
Greece	0.8	2.2	2.4	—	—	—
Iceland	—	—	—	—	—	—
Ireland	0.2	1.3	1.4	0.1	1.5	1.8
Italy	23.4	10.5	13.4	—	—	—
Japan	—	—	—	2.3 (1992)	1.1	1.7
Luxembourg	0.0	0.0	0.0	0.0	0.0	0.0
Mexico	—	—	—	—	—	—
Netherlands	72.8	94.5	100.0	3.3	21.5	22.3
New Zealand	—	—	—	0.2 (1994)	2.1	7.2
Norway	0.1	0.1	23.1	—	—	—
Portugal	2.6	8.3	11.5	0.7	9.5	17.4
Spain	3.6	2.3	4.8	1.0	2.2	4.7
Sweden	8.8	6.0	95.9	—	—	—
Switzerland	1.1	1.8	89.8	0.8	5.1	62.5
Turkey	—	—	—	—	—	—
UK	14.2	4.4	6.2	2.0	2.7	3.5
US	335.8	9.8	13.8	49.0	7.1	9.8
Total OECD	584.3	7.6	13.0	—	—	—

[a] except where noted; [b] indicates data not available; [c] IEA estimates; [d] DH systems data not including industrial or commercial CHP

Sources IEA/OECD electricity statistics and country reports in IEA (1994b) and UNICHAL (1991)

CHP does not represent a significant share of the total electricity supply for any country, with the exception of the Netherlands, Denmark, and Finland. However, CHP production is more appropriately compared with fossil fuels based electricity supply, since most CHP is based on fossil fuel technologies, for which some level of siting discretion exists.[5]

Fossil fuels contributed 58.9% to electricity supply in OECD countries in 1993, and CHP contributed 13% to fossil-fuelled electricity production in 1993.[6] Of the 16 countries that reported CHP production information in 1993, the contribution of CHP to total fossil electricity supply is greater than 70% for five countries, between 10% to 30% for five countries, and below 10% for six countries.

The five countries where CHP provides greater than 70% of the fossil fuel based supply are the Netherlands, Sweden, Switzerland, Denmark, and Finland. While Swiss and Swedish fossil-fired electricity production is based largely on CHP, this must be viewed in the light of the fact that fossil-fired electricity production is a very low percentage of total electricity production in these countries – two and six per cent respectively. In contrast, fossil-fired electricity represents the significant share for the Netherlands, Denmark, and Finland. In the Netherlands and Denmark, electricity production is almost entirely supplied by fossil fuels – 95 and 97% respectively, and the 100% CHP share in the Netherlands and the 90% CHP share in Denmark represents an important contribution to the national electricity supply in these countries. In Finland, 45% of electricity production is fossil-fired and 72% of this is supplied by CHP.

Regarding the mix of fuels employed by CHP systems, Table 3 indicates the fuel sources for CHP plants and fossil-fired electricity only plants. As would be expected, autoproducer CHP plants used a much higher share of natural gas than did public CHP plants. In addition, compared with fossil-fired electricity-only plants, CHP facilities use a much higher share of natural gas and solid fuels such as wood and wastes.

Outlook for CHP in Electricity Supply

Table 4 provides estimates for future electricity production through CHP. A sampling of the types of projects being installed includes relatively large plants, many over 100 MW, a large number of which are gas-fired. The most dramatic increase in electricity production is expected in the Netherlands, where the supply is expected to more than double by the year 2000. This table implies an increase of approximately 8.2 GW of CHP capacity among the countries reporting.

Government Support of CHP

Most IEA member governments have tried to increase their countries' use of CHP through information and audit programmes, rules governing CHP relationship with utilities, financial incentives, and support for R & D. The motivation behind these measures

[5] In Switzerland, two nuclear facilities are operated in a CHP mode, providing heat to a factory and district heating system respectively.

[6] Data on CHP were not available for all OECD countries. All generalizations about the share of CHP are based on an extrapolation for those countries for which data was available.

Table 3

Fuel shares for CHP autoproducers, CHP public producers, and electricity-only producers. 1993 (%)

Country	Autoproducers				Public producers				Fossil fuel electricity-only producers			
	Coal	Other solid fuels	Oil	Natural gas	Coal	Other solid fuels	Oil	Natural gas	Coal	Other solid fuels	Oil	Natural gas
Australia	—[a]	—	—	—	—	—	—	—	88 8	0 0	1 9	9 4
Austria	—	—	—	—	—	—	—	—	33 2	0 0	13 7	53 2
Belgium	—	—	—	—	78 3	0 2	10 8	10 8	57 4	6 5	3 8	32 3
Canada	—	—	—	—	0 0	0 0	31 0	69 0	76 2	1 5	9 6	12 7
Denmark	19 6	4 9	53 9	21 6	87 1	3 8	3 1	6 0	85 6	1 9	9 4	3 1
Finland	17 2	59 3	6 7	16 7	45 2	23 8	3 0	28 0	55 2	29 7	3 9	11 2
France	—	—	—	—	—	—	—	—	75 8	2 4	14 7	7 0
Germany	—	—	—	—	—	—	—	—	87 2	1 2	2 8	8 8
Greece	0 0	25 1	60 9	14 0	—	—	—	—	79 6	0 0	20 4	0 0
Iceland	—	—	—	—	—	—	—	—	0 0	0 0	100 0	0 0
Ireland	16 1	22 6	5 9	55 4	—	—	—	—	38 7	16 1	15 7	29 5
Italy	4 9	1 6	42 3	51 2	10 9	5 5	25 8	57 9	12 9	0 2	66 6	20 3
Japan	—	—	—	—	—	—	—	—	27 9	1 9	37 3	32 9
Luxembourg	—	—	—	—	—	—	—	—	78 1	12 6	5 9	3 4
Mexico	—	—	—	—	—	—	—	—	11 1	0 0	72 5	16 4
The Netherlands	4 1	9 6	20 3	65 9	41 1	0 1	0 4	58 4	—	—	—	—
New Zealand	—	—	—	—	—	—	—	—	6 2	0 0	0 8	93 0
Norway	—	—	—	—	28 0	72 0	0 0	0 0	40 9	59 1	0 0	0 0
Portugal	9 6	35 8	54 6	0 0	0 0	0 0	100 0	0 0	56 4	0 0	43 6	0 0
Spain	17 7	8 5	53 4	20 4	—	—	—	—	87 5	0 3	11 9	0 3
Sweden	4 0	52 3	37 5	6 2	33 9	30 5	21 2	14 3	9 4	0 0	90 6	0 0
Switzerland	0 0	24 3	33 3	42 4	0 2	78 4	8 1	12 3	—	—	—	—
Turkey	—	—	—	—	—	—	—	—	62 2	0 4	15 6	21 9
UK	22 1	5 6	22 5	49 8	—	—	—	—	75 3	0 9	10 7	13 2
US	26 1	26 6	6 1	41 3	71 3	0 2	16 6	12 0	79 1	2 0	4 6	14 4
Total OECD	24 5	25 3	8 5	41 7	60 6	4 7	9 6	25 1	68 6	1 7	13 6	16 2

[a] indicates data not available

Note All figures are based on estimates of share of CHP electricity production The underlying statistics count all output from electricity plants having CHP units as CHP production, even in cases where CHP units represent a small portion of a plant's capacity, and where CHP units are not always run in the CHP mode Coal includes coke oven and blast furnace gas, other solid fuels include peat, wood, wastes, and other solid fuels, oil includes all liquid fuels and refinery gas, and natural gas includes gasworks gas

Source IEA/OECD electricity statistics

Table 4
Outlook for CHP in 2000 AD

Country	*CHP electricity production (TWh)*		*CHP electricity capacity (GW)*	
	1993[a]	*2000*	*1990*[a]	*2000*
Australia	6 1 (3 7%)	9 2		
Canada	—	—	2 0 (2 0%)	5 1 (3 7%)
Finland	19 9 (32 5%)	28 5 (36 1%)	—	—
Ireland	—	—	0 1 (1 5%)	0 1 (2 7%)
Netherlands	18 0 (25 0%)	44 0	3 3 (21 5%)	8 0 (39 0%)
New Zealand	—	—	0 2 (2 1%)	0 7 (7 7%)
Spain	—	—	1 0 (2 2%)	2 2 (4 4%)
Switzerland	1 1 (1 8%)	1.9 (3 0%)	0 8 (5 1%)	0 8 (6 7%)
UK	—	—	2 0 (2 7%)	4 0 (5 0%)
Total	—	—	9 4	20 9

[a] except where noted

Note The potential electricity supply from CHP for Australia is estimated for an unspecified year CHP electricity supply for Switzerland in 2000 AD is based on the estimated growth rate, figures in parentheses show CHP share of total electricity production or capacity)

is the desire to exploit the potential efficiency benefits of CHP and to diversify sources of electricity production, as well as the belief that impediments in the marketplace will prevent the appropriate level of CHP from being realized.

Some governments have elected to tilt the field in favour of CHP, in part because it is an infant industry and needs some degree of protection in order to develop. Similarly, the high capital costs of DH systems have led some governments to assist them through up-front financing and to absorb some of the risk till the system becomes fully subscribed. Under selected circumstances, governments have taken steps to minimize this risk by guaranteeing a customer base. Other governments have intervened because the playing field was thought to be biased against CHP systems (e.g., utility recalcitrance to interconnect with them). In these cases, government efforts to promote CHP have generally tried to remove potentially discriminatory treatment vis-à-vis electric utility policies.

It should be noted, however, that little evidence shows that the government policies are designed so as to reward a particular attribute of CHP, such as efficiency or environmental compatibility. Many governments appear to support CHP on the basis that it provides a public good, and do not require individual projects to demonstrate efficiency advantages, in either design or operation, to qualify for the policy benefits. Noted exceptions include the US rules on efficiency requirements for a system to achieve qualifying facility status; Italian payment premiums from utilities to systems that exceed a stated efficiency level; and Canadian tax support for CHP systems that have heat rates less than a specific target.

The different types of governmental approaches – information, institutional, financial, and R & D – employed to support CHP are discussed below Of course, these should be viewed in light of the countries' energy resource endowments and their governments'

role in energy policy. Caution is also recommended before inferring any cause-and-effect relationship between these measures and the degree to which CHP contributes to electricity production. Other factors are obviously instrumental in influencing CHP development, for example, industry mix, urban density, and heating degree days.

Information and Feasibility Studies

Many governments of member countries provide information on CHP systems. For example, Germany provides leaflets, brochures, and books; and the Netherlands, Switzerland, and UK provide project profiles and case studies.

Several governments underwrite the costs of feasibility studies for CHP in given applications. France and Italy provide up to 50% of the cost of the feasibility study. The Netherlands provides 50% of the cost of the evaluation, up to Gld 50 000. Turkey funds industrial audits, while UK provides financial assistance for consulting services on identification, design, and management of projects that have a good chance of providing energy savings in excess of 10%.

Institutional Arrangements

The most common type of institutional support offered by member governments is the requirement that utilities connect to, and purchase power from, CHP systems. In some cases, the rates at which the power is purchased is specified or set by formula. In 1980, only Austria, Italy, and Spain, provided legal rules to connect cogeneration plants to the electric grid. As of 1992, 10 countries had granted legal rights to autoproducers to sell electricity to the local utility (Table 5). The purchase prices are often based on avoided costs. Price controls are often added, and can be implemented in one of the three ways:

- prices legally fixed (Italy);
- prices reviewed by committees (government committees or those consisting of different groups, including manufacturers and electric utilities); and
- prices based on specific projections by a governmental institution (US).

The Netherlands and Italy have recently allowed utilities to enter into joint ventures with industrial partners – the Netherlands even encourages such joint ventures. Most of the CHP estimated in Belgium's industrial sector are expected to come about through joint-venture projects between ELECTRABEL and several industrial partners (Dufait *et al.* 1992).

Some countries have instituted requirements that buildings in the proximity of a DH network be connected to the system. The motivation is to shelter the DH system during the early years when capital expenditures are high and revenues low, with the expectation that the fully-developed system will provide lower cost energy than the alternatives. For example, Denmark reserves about 60% of the heating market for DH and eventually CHP. Residential buildings exceeding 250 kW demand and in the proximity of either a DH or natural gas network are required to be connected to either the former or the latter.

In 1990, Denmark established a policy that all new electric capacity through the mid-1990s be achieved primarily through the conversion of existing DH heat-only plants into small-scale CHP plants fuelled by gas, refuse, or biomass. As a consequence, the devel-

Table 5

Right to sell surplus electricity from CHP plants and prices for electricity fed into the grid

Country	Right to sell electricity	Typical price	Price control
Australia	Yes	Peak: ~9 03 cents	Incentive
Austria	Yes	Avoided costs	By decree
Belgium	Yes	Avoided costs	Review
Canada	—	—	—
Denmark	Yes	0.3 DKr/kWh	Regulated by act
Finland	—	—	Determined by all users
France	Yes	Set relative to utility prices	By decree
Germany	Association agreement	0 08–0.1 DM/kWh	—
Greece	—	—	—
Ireland	Yes	Avoided cost	—
Italy	Yes	37–137 L/kWh	Fixed by decree
Japan	—	—	—
Luxembourg	—	—	—
The Netherlands	Yes	Avoided cost	Review commission
New Zealand	Yes	Negotiated by buyers and sellers	None
Norway	—	—	—
Portugal	Yes	Incentive	By decree
Spain	—	—	—
Sweden	Yes	Avoided cost	Review
Switzerland	Yes	Other new plants	—
Turkey	—	—	—
UK	Yes	Pool prices	—
US	Yes	Avoided cost	Contract for each new plant

Source Country reports in IEA (1994b)

opment of a coal-fired facility was changed to gas. Each district council was required to prepare a plan for the supply of heat in the municipality, with the requirement that all heat supply systems in excess of 1 MW be analysed for conversion to CHP.

Some countries allow CHP systems to use fuels that are otherwise constrained for power generation. For example, Portugal limits the use of oil products for the production of electricity (as per the Commission of European Communities directive), but relaxes the rule for CHP systems, if they have a permit based on an analysis of alternative fuels. In the UK government, authorization is required to use natural gas for power generation. CHP plants and combined-cycle gas turbines normally receive this authorization.

Financial Incentives

Several member-governments provide financial incentives to developers of CHP systems. The incentives are either grants based on installed capacity or operating efficiency, or

tax incentives. Canada offers preferential tax treatment for capital depreciation for energy for energy-efficiency equipment. CHP systems with net heat rates of 7000 Btu/kWh or less, qualify for an accelerated write-off schedule of 25%, 50%, 75%. Denmark offers an investment subsidy of up to 30% of total investment costs for CHP in industry and greenhouses. France provides an exemption on fuel taxes for gas and low-sulphur heavy-fuel oil used in CHP plants, an exemption of 50% of the professional tax on the asset value of the plants, and a possibility of accelerated amortization for the investments. Italy provides investment support of up to 40% of the capital cost for CHP systems with capacity in excess of 10 MW_{th} or 3 MW_e and up to 50% for DH systems recycling heat from electricity production or industrial processes. Japan offers low-interest loans (between six to seven per cent) and a choice among tax incentives. Luxembourg provides financial incentives of 25% of the costs of systems that promote energy saving in general or use new and renewable energy resources (up to LF 60 000). The Netherlands provides up to 25% of the investment costs for CHP schemes in industry, commercial buildings, and horticulture (up to Gld 500 for engines and Gld 650 for gas or steam turbines below 2 MW, not to exceed Gld 20 million per project). Portugal provides financial assistance to CHP schemes through the System of Incentives for the Rational Use of Energy (SIURE) programme. Sweden grants a fixed subsidy per kW for installed capacity of CHP (Skr 4000) for systems that are fuelled by biofuels. CHP systems are exempt from energy taxes, although the share of the fuel that can be assigned to heat production is still subject to the CO_2 tax. In UK, own-generation systems, that consume more than 51% of the electricity on site, are exempt from the 11% fossil fuel levy.

R & D

CHP R & D focuses on improving performance and reliability, reducing noise and impacts on the environment, and developing smaller and more modular units. New fuels (e.g., biomass) and new prime movers (e.g. Stirling engines) are also being investigated. Table 6 shows the CHP activities of the national R & D programmes. Of course, R & D is being conducted by other organizations as well.

Table 6

National R & D Activities on CHP

Country	Activities
Belgium	University and institute research and economic studies in Flanders
Denmark	Further use of natural gas, biomass-fuelled CHP
Finland	Automation of DH network and CHP systems
Germany	Demonstration projects for prototypical applications
Ireland	Demonstration projects under the THERMIE programme
Japan	Fuel cells, petroleum-fuelled CHP, smaller plants, environmental requirements
Switzerland	Low emission motors, design tools for small plants
UK	Lower costs, reliability, environment, new prime movers (fuel cells, Stirling engine), biofuel demonstration
US	Advanced systems, emission reduction, high electric-to-thermal capacity

Collaborative research on district heating and cooling (DH&C) has been carried out under an IEA implementing agreement since 1983. The objective of this programme is to demonstrate the environmental and economic benefits of introducing DH&C and CHP schemes It has assessed technical areas such as piping, transmission fluids, heat meters, heat production technologies, and system simulation models for DH&C and CHP. Canada, Denmark, Germany, Finland, Korea, the Netherlands, Norway, Sweden, UK, and the US are currently participating in this programme. The main subjects include:

- a design guide for integrating district cooling and CHP;
- advanced transmission fluids;
- piping technology, including a manual on district heating pipelines;
- supervision of district heating networks;
- efficient sub-stations and installations; and
- development of long-term cooperation with Eastern European countries; and
- information exchange.

Conclusions

The factors likely to shape the future potential for CHP and district heating are listed below.

- Future energy prices, both for CHP plants and for competing systems.
- The need for new electricity capacity.
- The potential transformation of electric industry structures in member countries.
- The presence and expansion, within member countries, of industries that are good candidates for CHP, as well as the continued electrification of the processes in some of these industries.
- Technical advances in CHP, competing electric and thermal processes, and district heating.
- Possible increases in environmental taxes and the uncertainty of their impact on CHP.

Many member countries are anticipating significant increases in CHP use through the end of the decade. The opportunities appear to be in applications that have historically dominated CHP development – industry (including greenhouses) and DH. Some member countries have taken steps to increase the likelihood that these expectations will be realized. The programmes discussed in the section on government support to CHP are typical of those that governments plan to continue. However, many of these policies do not seem to explicitly or logically reward those features of CHP, specifically environmental compatibility and energy efficiency, that are used to justify policy intervention in the first place. Moreover, additional analysis of the effectiveness of these policies is needed

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Session IX

Special Presentation

Cogeneration in Sugar Units

R Kannan[1]

Introduction

Cogeneration is being practised currently in many industries such as refineries, fertilizers, soda ash units, etc. Refineries use their heavy stock and fertilizer units utilize their feedstock as fuel for their high-pressure boilers. However, several industries have not made efforts to install cogeneration units mainly because their investment criteria have favoured expansion and diversification schemes over energy conservation projects. Further, the liquidity constraints prevailing in the economic system, cyclic/discontinuous loads in the units which reduce benefits of cogeneration, varying demand of steam/electricity during the day, and the changing pattern of energy consumption have contributed to the slow application of cogeneration in the industry.

Institutions have financed cogeneration systems in the industries through a variety of instruments such as loans, leases, lines of credit, etc. The main criteria used in financing these systems have been the creditworthiness of the borrower, acceptability of the financing structure, tying of fuel supply and sale of surplus power to the state electricity board (SEB), and the viability of the whole scheme.

While cogeneration is practised widely in the sugar industry, sale of excess cogenerated power to the grid is a new phenomenon. However, recently, use of high-pressure boilers, predrying of bagasse, extraction/condensing turbines, and other energy economy measures are picking up.

Cogeneration in Sugar Units

Viability Parameters

The parameters which determine the viability of the cogeneration schemes in sugar units are discussed in the following section.

[1] Industrial Credit & Investment Corporation of India Ltd, Mumbai, India.

Size of Unit and Configuration of the Existing Equipment

Viability of cogeneration schemes improves if the sugar units are of a large size. Internationally, most of the sugar units are above 4000 tcd, and, hence, cogeneration projects are desirable in these units. Every cogeneration scheme should be tailored for the existing machinery configuration. In the case of new plants, such a problem does not exist as the design provides the flexibility for cogeneration right from the initial stage. However, before implementing the cogeneration scheme, the power/steam consumption should be optimized by installation of a hydraulic drive for mills, pre-evaporation prevention of steam leakage, proper instrumentation, etc., to have a proper balance between steam and power. The steam consumption should be around 40% of cane and the power consumption about 12 to 15 kWh/tonne of cane crushed.

Availability of Cane and Duration of the Crushing Season

The cane availability should be adequate to ensure full crushing for at least 160 days in a season. Low or fluctuating crushing levels bring down the viability.

Availability of Alternate Fuel

During the off-season, the availability of alternate fuel at reasonable rates is an important prerequisite for cogeneration.

Problems of Grid-interfacing with SEBs

The arrangements with SEBs for purchase of power in general and the financial position of the particular SEB, as also its ability to discharge the obligations, should be thoroughly gone into before interfacing with the grid. Other important aspects that need to be looked in to are the price of power, protection of cogeneration equipment from voltage/frequency fluctuations, and failure in the grid, etc. The net realization of power should be at least Rs 2 to 2.25/unit (net of wheeling/banking charges). The overall arrangement with the SEB for purchase of power is the most critical and time-consuming step.

Fibre Content of Cane

The fibre content of cane should be at least 15%, i.e., 30% of the cane crushed with 50% moisture. If there is an adequate market available for surplus bagasse at Rs 300– 400 per tonne nearby, then utilization of bagasse for cogeneration may not be a viable option.

Viability Computation

The viability of cogeneration in a sugar unit may be evaluated on the basis of the following assumptions.

- The boiler pressure range is assumed between 45 to 65 kg/cm^2 as higher pressures and high temperatures may need special materials of construction.
- The turbine steam rates are assumed as under (in kg/kWh):
  - 45 kg/cm^2 – Condensing turbine· 6; back-pressure turbine: 8
  - 65 kg/cm^2 – Condensing turbine: 5; Back pressure turbine: 7

Table 1

Assumed generation

	2500 tcd				3500 tcd			
	45 kg/cm²		65 kg/cm²		45 kg/cm²		65 kg/cm²	
	Season	Off-season	Season	Off-season	Season	Off-season	Season	Off-season
Generation (MW)	10 52	11 25	12 29	13 50	14 97	15 75	17 50	19 00
Consumption (MW)	4 50	1 00	4 50	1 00	6 25	1 00	6 25	1 00
Export (MW)	6 02	13 25	7 79	12 50	8 72	14 75	11 25	18 00

Notes

- Season days are assumed as 140
- Steam is assumed at 40% of cane
- Operating costs 5% of capital cost during season, 7 5% of capital cost during off-season
- The prices of bagasse and alternate fuel are assumed at Rs 200 and Rs 300 per tonne
- The power realization is assumed at Rs 2 0/unit net of banking/wheeling charges

- The cost of project would be Rs 20 to 30 crores for 2500 tcd and Rs 25–38 crores for 3500 tcd depending upon existing equipment configuration, pressure of the boiler, and whether the system would generate power during off-season also. Table 1 gives the assumed generation figures.

It may be noted that the above assumptions are mainly indicative and could vary marginally from plant to plant.

Results of Viability Calculation

Based on the above assumptions, the following conclusions on viability could be drawn. The impact of the size of the unit, boiler pressure, fibre content, season duration, and steam rate in turbines on the viability are given in Table 2 (see next page).

As stated earlier, each cogeneration scheme has to be examined in detail, and it is difficult to draw general conclusions. However, the above article is an attempt to analyse the issues based on certain assumptions which can be normally considered representative. The article also brings out the importance of water rate, size of the plant, boiler pressure, and duration of the season. As there are only about 50 plants above 2500 tcd, the potential for cogeneration would be limited unless we are able to make cogeneration projects from 2500 tcd units viable as well.

While cogeneration is practised widely, the sale of excess power to the grid is a new phenomenon. Use of high pressure boilers, predrying of bagasse, use of extraction-cum-condensing turbines, and other energy–economy measures are picking up.

Table 2

Viability calculations

Case no	Working parameters	Viability
1	2500 tcd, operating pressure 45 kg/cm^2 to 65 kg/cm^2, and working during the season only	Become marginally viable if the season days are increased to at least 200 days and steam rates are improved to at least 7.5 kg and 5.5 kg per kWh for back-pressure and condensing turbines respectively
2	3500 tcd, operating pressure at 45 kg/cm^2, and working during the season only	—
3	2500 tcd, operating pressure 45 kg/cm^2, and working during the off-season also	Become viable if steam rates are improved to 7 5 kg and 5 5 kg per kWh as stated above
4	3500 tcd operating pressure 65 kg/cm^2, and working during the season only	—
5	2500 tcd, operating pressure 65 kg/cm^2, and working during the off-season also	Viable, but if fibre content drops to 14%, viability would be affected
6	3500 tcd, operating pressure 45 kg/cm^2 and working during off-season also	—
7	3500 tcd operating at 65 kg/cm^2 and working during off-season also	Viable